OPERATING HEALTH ANALYSIS OF ELECTRIC POWER SYSTEMS

A Thesis Submitted to the College of
Graduate Studies and Research
in Partial Fulfillment of the Requirements
for the Degree of

Doctor of Philosophy

in the
Department of Electrical Engineering
University of Saskatchewan
Saskatoon

By

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Spring 1998

0-612-27407-1

To my wife, Parvaneh, and my daughter, Farnaz,
with thanks for encouragement and support

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ACKNOWLEDGMENTS

The author would like to express his sincere gratitude and appreciation to his supervisor, Dr. Roy Billinton, for his criticisms, guidance and consistent encouragement throughout the course of this research work. His advice and assistance in the preparation of this thesis is thankfully appreciated. The author would like to express his appreciation to the members of his committee, Dr. T. S. Sidhu, Dr. J. Bugg, Dr. N. A. Chowdhury and Professor D. E. Dodds for their careful reviews of this work.

The author takes this opportunity to acknowledge the patience, encouragement and moral support provided by his parents, brothers, sisters and all other family members. Special thanks are extended to his wife, Parvaneh, and his daughter, Farnaz, for their patience and constant encouragement.

This work was financed by the Ministry of Culture and Higher Education of Iran and the University of Saskatchewan in the form of graduate scholarship. Both financial supports are thankfully acknowledged.

ABSTRACT

The required level of operating reserve to be maintained by an electric power system can be determined using both deterministic and probabilistic techniques. Despite the obvious disadvantages of deterministic approaches there is still considerable reluctance to apply probabilistic techniques due to the difficulty of interpreting a single numerical risk index and the lack of sufficient information provided by a single index. A practical way to overcome these difficulties is to embed deterministic considerations in the probabilistic indices in order to monitor the system well-being. System well-being can be designated as healthy, marginal or at risk. The concept of system well-being is examined and extended in this thesis to cover the overall area of operating reserve assessment.

Operating reserve evaluation involves the two distinctly different aspects of unit commitment and the dispatch of the committed units. Unit commitment health analysis involves the determination of which unit should be committed to satisfy the operating criteria. The concepts developed for unit commitment health, margin and risk are extended in this thesis to evaluate the response well-being of a generating system. A procedure is presented to determine the optimum dispatch of the committed units to satisfy the response criteria. The impact on the response well-being of variations in the margin time, required regulating margin and load forecast uncertainty are illustrated. The effects on the response well-being of rapid start units, interruptible loads and postponable outages are also illustrated.

System well-being is, in general, greatly improved by interconnection with other power systems. The well-being concepts are extended to evaluate the spinning reserve requirements in interconnected systems. The interconnected system unit commitment problem is decomposed into two subproblems in which unit scheduling is performed in each isolated system followed by interconnected system evaluation. A procedure is illustrated to determine the well-being indices of the overall interconnected system. Under normal operating conditions, the system may also be able to carry a limited amount of interruptible load on top of its firm load without violating the operating criterion. An energy based approach is presented to determine the optimum interruptible load carrying capability in both the isolated and interconnected systems.

Composite system spinning reserve assessment and composite system well-being are also examined in this research work. The impacts on the composite well-being of operating reserve considerations such as stand-by units, interruptible loads and the physical locations of these resources are illustrated. It is expected that the well-being framework and the concepts developed in this research work will prove extremely useful in the new competitive utility environment.

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LIST OF SYMBOLS

HLI	Hierarchical Level I
HLII	Hierarchical Level II
HLIII	Hierarchical Level III
LOLE	Loss Of Load Expectation
LOEE	Loss of Energy Expectation
GSOSR	Generating System Operating State Risk
GSRSR	Generating System Response State Risk
CSOSR	Composite System Operating State Risk
LFU	Load Forecast Uncertainty
RBTS	Roy Billinton Test System
MRBTS	Modified Roy Billinton Test System
IEEE-RTS	IEEE-Reliability Test System
FLCC	Firm Load Carrying Capability
ILCC	Interruptible Load Carrying Capability
OILCC	Optimum Interruptible Load Carrying Capability
ORR	Outage Replacement Rate
MT	Margin Time
RR	Response Rate
RM	Regulating Margin
RRM	Required Regulating Margin
CEA	Canadian Electrical Association
COPT	Capacity Outage Probability Table
OR	Operating Reserve
SPC	Spinning Capacity
SC	Single Criterion
MC	Multiple Criteria
EPRI	Electric Power Research Institute

1. INTRODUCTION

1.1 Introduction

Electric energy is an essential ingredient in the development of a modern society. Almost all aspects of daily life depend on the use of electrical energy and the performance of a power utility can be measured in terms of the quality and reliability of the supply. Electric power utilities have invested a substantial amount of capital in generating stations, transmission lines and distribution facilities to supply electrical energy to their customers as economically as possible and with a reasonable assurance of continuity, safety and quality. This creates the difficult problem of balancing the need for continuity of power supply with the costs involved. However, no matter how much money, time and effort are invested, and no matter what advanced technologies are utilized, it is impossible to totally eliminate the possibility of equipment outages and the need to remove equipment from service to perform preventive maintenance [1]. It is, therefore, not feasible economically and technically to attempt to design and operate a power system with one hundred percent reliability. Power system engineers have always attempted to respond to societies' expectations and to achieve the highest possible reliability at an affordable cost. A high level of customer reliability can only be attained by incorporating reliability considerations in all aspects of power system planning, design and operation.

1.2. Power System Reliability

System reliability is an important consideration for planners, designers and operators. Reliability can be defined as the probability of a system performing its required function for the period of time intended under the operating conditions encountered [2]. The concept of power system reliability is extremely broad and covers all aspects of the ability of the system to satisfy the consumer requirements [3-6]. Due to the wide ranging implications of the term reliability, it is necessary to subdivide it into more specific segments. A simple but reasonable subdivision of the term "system reliability" can be made by considering the two basic and fundamental aspects of system adequacy and security as shown in Figure 1.1 [2,3,7,8,9].

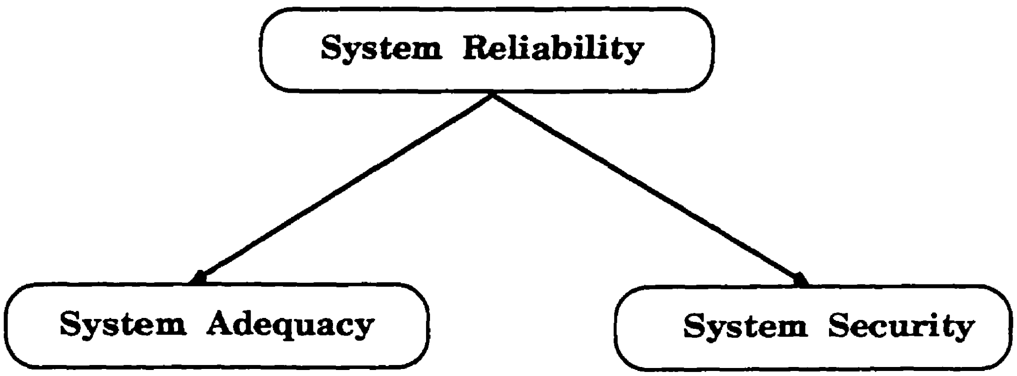

Figure 1.1: Subdivision of system reliability.

1.2.1 Adequacy and Security

Adequacy and security are major concerns for power system planners and operators. System adequacy relates to the existence of sufficient facilities within the system to satisfy the consumer load demand. This includes the necessary facilities to generate sufficient electrical energy and the associated transmission and distribution required to transfer the energy to the customer load points. Adequacy is therefore concerned with static conditions which do not include system disturbances. System security, on the other hand, relates to the ability of the system to cope with perturbations arising within it. These include the conditions associated with both local and widespread disturbances and the loss of major generation and transmission facilities. It is clear that adequacy assessment and security analysis deal with quite different reliability issues and involve different assessment techniques. The evaluation of Loss Of Load Expectation (LOLE) and Loss Of Energy Expectation (LOEE) reside in the area of adequacy [10-12]. Quantification of spinning or operating capacity requirements, which is the subject of this thesis, falls in the domain of security assessment.

1.2.2 Functional Zones and Hierarchical Levels

The evaluation techniques used in reliability analysis of power systems can be categorized in terms of their application to the three basic functional zones of generation, transmission and distribution. These functional zones can be combined to create Hierarchical Levels (HL) for the purpose of conducting system reliability analysis [2]. Reliability assessment at the different hierarchical levels and functional zones has undergone continous development and application since the 1930s. The development can be seen from the bibliographies [13-17] published in the IEEE which contain many papers on reliability assessment of power systems. The functional zones and hierarchical levels are shown in Figure 1.2. Hierarchical Level I (HLI) is concerned only with the generating facilities. Reliability evaluation at HLI provides a quantitative assessment of the ability of the generating system to satisfy the total system demand. Both generation and the associated transmission facilities are considered in HLII reliability evaluation. The combination of generation and transmission is known as a composite or bulk system. Composite system reliability evaluation techniques, therefore, include the ability of the transmission system to deliver the generated energy to the major load points. HLIII studies are concerned with the overall assessment of the three functional zones. HLIII adequacy assessment involves the consideration of all the three functional zones in order to evaluate customer load point adequacies [6].

The reliability indices calculated at each hierarchical level are physically different. System reliability is usually predicted using one or more indices which quantify expected system reliability performance and implemented using criteria based on acceptable values of these indices. This research

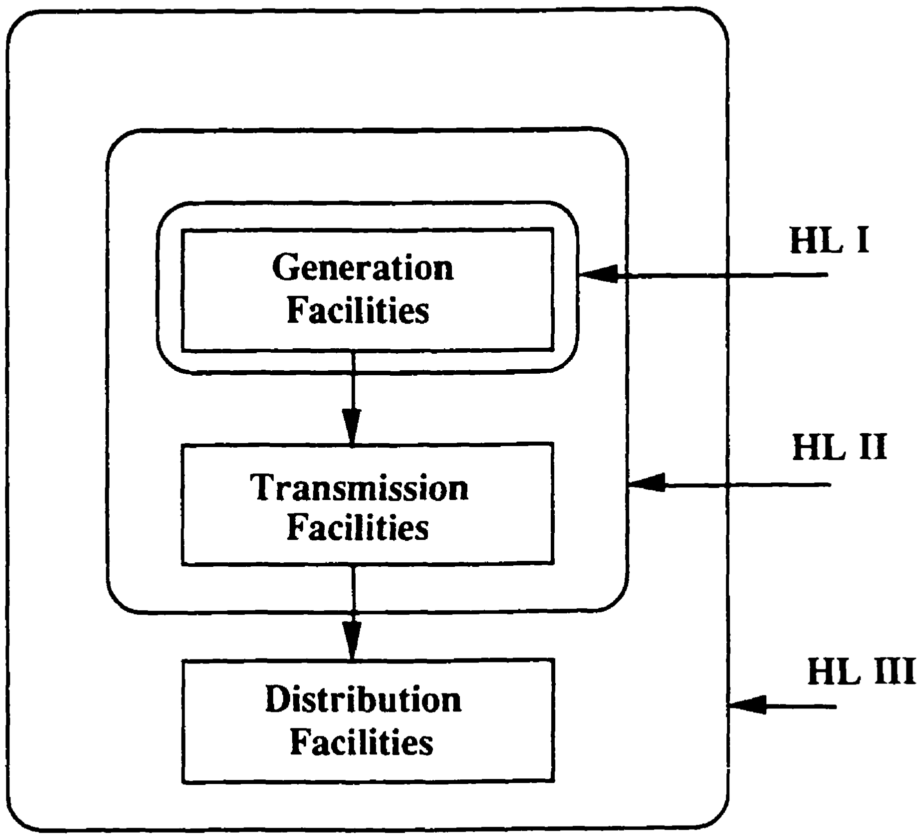

Figure 1.2: Hierarchical levels for reliability analysis.

project, is concerned with operating reserve assessment at HLI and HLII, which is in the domain of system security.

1.3 Power System Operation

The total problem of power system reliability evaluation at HLI can be divided into the two conceptually different areas of static and operating reserve assessment. The static capacity area relates to the long-term evaluation of the overall system requirements. Operating reserve assessment, on the other hand, is related to the short-term evaluation of the actual capacity required to meet a given load demand [3]. Considerable efforts have been devoted to static capacity assessment [9-16]. There is, however, relatively little published material in the area of operating reserve assessment. This research work is restricted to the area of operating reserve assessment.

A power system operator is continuously faced with the problem of making good decisions rapidly. This imposes many burdens in order to ensure the system is operated economically and with an acceptable level of reliability. Operation of a power system involves short term load forecasting and the subsequent scheduling of sufficient generating capacity. Operating reserve must also be scheduled in order to account for unanticipated load changes and/or sudden outages of generation plant. Once this capacity is scheduled and in operation, the dispatcher is committed for the period of time needed to start up and synchronize additional generating plant. This delay, known as lead time, depends on the type of generating units available for service [3,18]. It may be quite short for hydraulic or gas turbine units and much higher for conventional thermal units [19]. The system reliability can be improved by increasing the system generating reserve. This, however, will increase the system operating cost. The reserve in the system, therefore, should be scheduled in such a way that both reliability and economic constraints are satisfied.

The traditional deterministic approaches used for reserve scheduling, impose operating constraints where the loss of a single circuit or generator must be tolerated. This is commonly referred to as an "N-1" criterion [20]. The essential weakness of these approaches is that they do not assess the actual system risk as they ignore the probabilistic or stochastic nature of system behavior and component failures. Power systems therefore sometimes are operated under constraints imposed by events which are low in probability of occurrence or severity of consequence even when the constraint imposes significant opportunity cost, such as limiting economic interchanges between power system participants [21,22]. Considerable attention has been devoted in the literature to the problem of unit commitment where the basic objective in determining the required spinning reserve is to minimize the total operating cost [23-31]. Under this condition, a system faces different degrees of risk throughout the day. The deterministic methods obviously do not respond to, nor they reflect, the probabilistic or stochastic nature of system behavior [3,22]. They lead to inconsistent decisions and variable operating risk levels.

Probabilistic techniques, however, can provide a comprehensive and realistic evaluation of the risk by incorporating the stochastic nature of system components. The first major probabilistic technique for operating reserve assessment, known as the PJM method, was proposed in 1963 by the Pennsylvania-New Jersey-Maryland power pool [32]. This method evaluates the probability of the committed generation just satisfying or failing to satisfy the expected demand during a specified time into the future, known as the lead time. The lead time required before a generating unit can be put into service depends on a number of factors including the type of unit in question. The delay time associated with a thermal generating unit can be several hours while rapid start and hot reserve units can usually be made available in a relatively short time. The original PJM method utilized a fixed lead time into the future. Modifications were subsequently made to the original PJM method to consider more detailed generation unit models [33]. This method has been extended to include rapid start and hot reserve units in [19]. A two state model was used for generating unit representation in the original PJM method. The concept of including a single generating unit derated state in the analysis was introduced in [34]. Reference 35 included multiple outages for large generating units. Spinning and non-spinning reserve such as rapid start and hot reserve form the operating reserve of a system. The term spinning reserve refers to unloaded generation which is already synchronized and therefore ready to serve additional demand [36,37]. The delay associated with a thermal unit can be reduced by maintaining the boiler in a banked state. Units in this operating mode are usually available within an hour, and are known as hot reserve units [3,18,19]. In addition to generating capacity, some utilities consider interruptible load as a part of their operating reserve. This load can be curtailed within an allowable time period in order to assist in keeping the system risk less than or equal to a specified value [38-40].

System reliability is normally improved by interconnecting a system with another power systems. Each interconnected system can then operate at a given risk level with a lower reserve than would be required without the interconnection. This concept is discussed in References 3 and 41-44 in a planning context. The PJM method was extended by application to interconnected system evaluation in [45-47]. Reference 47 developed a unit commitment technique for interconnected systems based on the "two risk concept" where an interconnected system must satisfy the single system risk at the isolated level and also the interconnected system risk at the interconnected level. A technique called the "expected energy assistance approach" is described in [48] to assess spinning reserve requirements in interconnected systems. This technique can be used to estimate an index for expected energy assistance between interconnected systems [49-50].

1.4 Objective and Scope of the Thesis

Probabilistic approaches generally base the design and operating constraints on the criterion that the risk of certain events must not exceed preselected limits. Many utilities still prefer to use a deterministic technique due to the difficulty in interpreting the numerical risk index and the lack of sufficient information provided by a single index [51]. There is considerable utility interest in including deterministic considerations in probabilistic indices [52]. A practical way to overcome these difficulties is to embed deterministic considerations into the probabilistic framework in the form of system well-being analysis. The system well-being is described by a set of mutually exclusive, exhaustive operating states designated as healthy, marginal and at risk. The concepts of system health, margin and risk in a system planning context for a composite generation and transmission system are presented in [53]. The events leading to each operating state can be identified and the probabilities associated with these operating states evaluated. The probabilities associated with the healthy and risk states can be considered as operating criteria. Reference 54 presents a probabilistic technique which extends the concepts of system operating health, margin and risk proposed in [53] to operating reserve assessment. The technique overcomes some of the difficulties in interpreting the risk index and also provides the system operator with important information on the degree of system well-being.

The basic objectives of this research work are to extend the concepts of system operating health, margin and risk

- in spinning reserve evaluation and allocation at HLI,
- in unit commitment in interconnected systems and
- in unit commitment in composite generation and transmission systems.

Operating reserve evaluation involves two distinctly different aspects. The first is unit commitment, in which the system operator decides which units and how many should be committed to satisfy the operating criteria. The second aspect is associated with the dispatch decisions regarding those units that have been committed [3]. Both sets of studies are necessary to obtain a complete picture of operating reserve assessment, i.e. these studies complement rather than substitute for each other. The question that is not answered in the unit commitment evaluation is as follows: Given that there are several subsets of the complete set of N generating units that would satisfy the expected demand, which of these subsets should be used in order to provide the minimum operating cost as well as an acceptable level of reliability. It is obvious that the difference between the operating capacity and the load is not a valid indicator of the ability of the system to respond to a loss of capacity [55-57]. Spinning reserve represents the remaining generating capacity of a unit and is considered to be independent of time. A certain portion of a system's spinning reserve must be available within a given time period for the purpose of protection in the event of a sudden loss of generating capacity or system load fluctuation [58]. The time period is referred to as the margin time and its actual value can vary from system to system [59]. The available generation change that can be achieved within a margin time is known as regulating margin. The concept of system operating health, margin and risk is extended to unit commitment evaluation in [60,61]. Once the number of committed units is determined, the next step is to make dispatch decisions regarding these units. Starting from an economic schedule [25,62], not only must the reserve be sufficient to make up for generating unit failures, but the reserve must be allocated among fast-responding and slow-responding units such that the specified system health and risk probabilities are satisfied. The system well-being framework has been extended in this research project to include response concepts.

The reliability of a power system is, in general, greatly improved by interconnection with other power systems [63-66]. Assessment of operating reserve requirements in an interconnected generating system should include not only the generation and load models of the participating systems, but also the tie-line model and the agreement between the interconnected systems. The problem of interconnected system unit commitment is decomposed into two subproblems. Unit scheduling is first performed in each isolated system in accordance with the specified operating criterion. Once the required number of committed units in each area is determined, the next step is to satisfy the operating criterion associated with the overall interconnected system. The criterion could be a specified interconnected system risk, an acceptable interconnected healthy state probability or both.

Composite system reliability evaluation is an important aspect of power system reliability evaluation. Operating reserve assessment in composite systems was examined in the final stage of this project. In a conventional HLI operating reserve assessment, the committed units are usually assumed to be connected to a common bus and serve the total system demand at that bus. The effect of transmission lines and the actual physical location of the generating units are neglected. In an actual power system, however, the generating capacity and loads are usually dispersed throughout the system and are not connected to a single bus. The committed capacity should therefore satisfy the operating criteria at HLI and also at HLII. Only the generating units are considered in an HLI operating reserve assessment and therefore the security constraints refer to the generation and total load demand. Operating reserve evaluation at HLII, however, can consider a number of additional constraints such as acceptable voltages at load buses, transmission line load carrying capabilities and real and reactive power considerations [73,74]. All of these constraints can be included in HLII operating reserve assessment. Operating reserve evaluation at HLII, therefore, includes the ability of the transmission system to deliver the generated energy to the major load points.

In conclusion, the concepts developed and the new quantitative indices should prove very useful to the system operator by providing information on the degree of system well-being, in addition to the system risk. This quantification cannot be achieved using deterministic techniques. The system well-being framework has also been applied in reliability evaluation of general engineering systems, small isolated electric power systems and HVDC transmission systems [75-79]

1.5 Summary of the Thesis

The thesis is structured as follows. Chapter 2 describes the basic concepts of well-being analysis. An overview of the available deterministic and probabilistic techniques used for operating reserve assessment is presented. The system well-being framework is examined in this chapter. The probabilistic techniques currently used for operating reserve assessment are compared with the proposed technique. The well-being framework is utilized in this chapter for unit commitment in which generating units are committed to the system to satisfy the operating criterion. The operating criterion could be a specified healthy state probability, a specified risk or both. The basic technique is illustrated in this chapter by determining the required amount of spinning reserve and the associated operating state probabilities for a given load level.

Chapter 3 presents an approach to evaluate the degree of system well-being in the responding capability of a generating system. The overall well-being of the system is identified as being healthy, marginal and at risk. A risk criterion designated as the Generating System Response State Risk (GSRSR) is used to determine the generating unit loading schedule. The committed units are loaded such that a specified GSRSR, an acceptable response health probability or both are satisfied. The operating cost varies with the different response criteria. An algorithm is described in this chapter to determine the unit commitment and optimum dispatch of the committed units based on the specified commitment and response criteria. The effects on the response health, margin and risk of factors such as margin time, required regulating margin and load forecast uncertainty are illustrated in this chapter.

The impacts of stand-by units, interruptible load and postponable outages on the response well-being of a generating system are illustrated in Chapter 4. The superposition of the unit commitment and response health, margin and risk are pictorially illustrated in this chapter in order to make these concepts more understandable. Reliable power system operation requires that a generating system has a high healthy state probability in both the unit commitment and response domains. A procedure is presented which utilizes a least costly adjustment to determine how far the acceptable load dispatch must be displaced from the most economic one. An important benefit of rapid start units and interruptible loads is that a system, which is in the marginal response state because of insufficient responsive reserve, can transfer to the healthy state when these elements are present.

Chapter 5 extends the concepts of unit commitment health analysis to evaluate the spinning reserve requirements in interconnected systems. The problem of interconnected systems unit commitment is decomposed into two subproblems. Unit scheduling is first performed in each isolated system in accordance with the specified operating criterion. Once the required number of committed units in each area is determined, the next step is to satisfy the operating criterion associated with the overall interconnected system. An approach is illustrated in this chapter to determine the required operating state probabilities. The magnitude of the operating reserve depends on factors such as operating criteria, generating unit failure rates, tie-line failure rates and load levels. A number of sensitivity studies are presented in this chapter to illustrate the impact of these factors on the single and interconnected system health, margin and risk probabilities.

A probabilistic technique is presented in Chapter 6 to evaluate the Optimum Interruptible Load Carrying Capability (OILCC) in both isolated and interconnected generating systems. A generating system with a given number of committed units can serve a target firm load level designated as the Firm Load Carrying Capability (FLCC). A set of ILCC can be determined for this number of committed units and the associated FLCC, which contains the interruptible load levels and the corresponding interruption times. The ILCC level which maximizes the expected energy supplied is taken from the set and designated as the OILCC of the generation system. The OILCC for two interconnected systems is determined by combining the two sets associated with the isolated systems. The interruption times are modified using an energy based approach to satisfy the interconnected system operating criteria.

Only the generating units are considered in an HLI operating reserve assessment and therefore the security constraints refer to the generation and total load demand. Operating reserve evaluation at HLII, however, involves a number of additional constraints such as acceptable voltages at load buses, transmission line load carrying capabilities and real and reactive power considerations. The concepts of system operating health, margin and risk for operating reserve assessment of a generating system is extended to composite operating reserve assessment in Chapter 7.

The basic concepts associated with unit commitment health analysis in composite generation and transmission systems are discussed in Chapter 7, assuming that the operating reserve in the system is only spinning reserve. System operating reserve can, however, include spinning and stand-by reserves and interruptible load. These additional elements can have considerable effect on composite system operating reserve assessment. The impact on the composite system well-being indices of variations in the size and locations of rapid start and hot reserve units are examined in Chapter 8. A procedure has been developed to determine the required number of units for a given load level and the associated well-being indices. This is then followed by a more detailed description of the proposed procedure to include stand-by units and interruptible load in composite system evaluation. The impacts of having generating capacity at different locations in a system should be of considerable interest in the new competitive environment.

The developed methods and techniques presented in this thesis have been applied to two reliability test systems, the Roy Billinton Test System (RBTS) and the IEEE-Reliability Test System (IEEE-RTS). The results obtained by utilizing the IEEE-RTS are illustrated in Chapters 2,3,4,5,6,7 and 8. The initial concept developments were done using the RBTS. Appendix A presents a wide range of results obtained using the RBTS. The required reliability data associated with the two test systems are given in Appendixes B, C and D.

Chapter 9 presents a summary and the conclusions to this research work.

2. BASIC CONCEPTS OF WELL-BEING ANALYSIS

2.1 Introduction

In a practical power system, the load demand varies considerably between weekdays and on-peak and off-peak hours. It is, therefore, not economical to continuously keep all the generating units on-line. The task of forecasting the load for a short time in the future and scheduling the appropriate and necessary operating capacity is complex. Sufficient capacity should be scheduled in order that the system is capable of handling deviations in customer demands and the possible loss of operating generating units. The system reliability can be improved by increasing the system generating reserve. This, however, will increase the system operating cost. The reserve in the system, therefore, should be scheduled in such a way that both reliability and economic constraints are satisfied.

Both deterministic and probabilistic techniques can be utilized to determine the required level of capacity reserve to be maintained by a system [80-84]. Deterministic approaches do not specifically recognize the probability of component failures in the assessment of operating reserve. Probabilistic techniques can be used to take into account the random outages of system components and other stochastic component behavior. The basic goal of a probabilistic technique is to maintain the system risk as close as possible but lower than an allowable risk at all times. Deterministic criteria are still widely used by many utility companies [51]. The reason for this is that these criteria are easier for system planners and operators to understand and apply than probabilistic approaches. A practical way to overcome these difficulties is to combine probabilistic indices with deterministic criteria to reflect the degree of power system well-being. The ability of a power system to supply load and to withstand disturbances can be described by a set of mutually exclusive exhaustive operating states designated as normal, alert, emergency and extreme emergency [52,85]. This framework is examined in this chapter for application to unit commitment in a generating system. The system well-being, as designated by the accepted deterministic criteria, can also be categorized as healthy, marginal or at risk. The probabilities associated with the healthy and risk states can be used as unit commitment criteria. A procedure for unit commitment and system risk evaluation is presented in this chapter. The benefits of the proposed method are compared with those of the current probabilistic methods.

2.2 Methods Used in Operating Reserve Assessment

There are a number of methods in general use to evaluate the operating reserve requirements in a power system. These methods can be classified into the two categories of deterministic and probabilistic approaches.

2.2.1 Deterministic Approaches

Deterministic techniques such as those shown below, recommend that the reserve capacity in a system should be equal to:

i) a percentage of system load or operating capacity,
ii) a fixed capacity margin,
iii) the largest unit contingency, or
iv) any combination of the above methods.

The most common deterministic criterion relates the reserve margin to the size of the largest unit or to some percentage of the peak load. Most Canadian utilities use the "largest unit contingency" method and some utilities complement this reserve assessment technique with an additional margin of some form [4]. The basic objective of deterministic approaches in determining the required operating reserve is to minimize the total operating cost [5,6,7,8] and in doing so a system faces different degrees of risk throughout the day. The essential weakness of deterministic approaches is that they do not assess the actual system risk as they ignore the probabilistic or stochastic nature of system behavior and component failures [9].

2.2.2 Probabilistic Approaches

In the operational phase, deterministic rules lead to over scheduling which, although more reliable, is uneconomic, or to under scheduling which, although less costly, can be very unreliable. A more consistent and realistic approach is one which recognizes the stochastic nature of system components and incorporates these factors in the assessment in a consistent manner [3]. The probabilistic techniques which have been developed in the area of operating capacity assessment can in general be divided into two categories, the PJM method and the security function approach.

2.2.2.1 Pennsylvania - New Jersey - Maryland Interconnected System Method (PJM)

The first major probabilistic technique for operating reserve assessment, is known as the PJM method and was proposed in 1963 by the Pennsylvania-New Jersey-Maryland power pool [32]. This method determines the probability of the committed generation just satisfying or failing to satisfy the expected demand during a specified time into the future, known as the lead time. This is the time during which no additional units can be placed in service [3]. In other words, during this period, the on-line capacity can not be replaced or added to in the case of an increase in the system load demand or the loss of some generating capacity. The lead time can be a few minutes to several hours depending on the type and the size of the units to be brought into service.

One of the problems faced by a system operator is to make on-line decisions based on the available information. The system condition is deterministically known at time t=0. The system risk is either zero or one depending on whether the load is less than or greater than the on-line capacity. The system operator therefore must calculate the risk for the period of time into the future needed for starting up and loading additional generating units. This risk is defined as the probability of the system generation just satisfying or failing to satisfy the load demand during the lead time [3]. This risk index is known as the unit commitment risk, and can be calculated using a capacity outage probability table [3]. The risk is given by Equation 2.1.

$$R(t) = \sum_{i=1}^{N} P_i(t) Q_i(t). \tag{2.1}$$

where,

$R(t)$	System risk at time t,
$P_i(t)$	Individual probability that the generation system is in state i at time t,
$Q_i(t)$	Probability that the system load will be equal to or greater than the generation in state i at time t,

N Total number of generation states.

In operating reserve assessment, $Q_i(t)$ is either zero or unity.

$Q_i(t) = 0$ when $load < C_i(t)$

$Q_i(t) = 1$ when $load \geq C_i(t)$

Where,

$C_i(t)$ = Total spinning capacity of the generation system in state i.

By arranging the capacity states in descending order as in a conventional capacity outage probability table, Equation 2.1 can be expressed as :

$$R(t) = \sum_{i=n}^{N} P_i(t) \tag{2.2}$$

Where n is an integer such that : $C_{n-1}(t) > load \geq C_n(t)$ and $R(t)$ is the cumulative probability of the nth state in the capacity outage probability table [3].

2.2.2.2 Security Function Approach

The security function approach is a general technique which was proposed in terms of various breaches of security [86-88]. The first step in an assessment of system security is the development of a set of events whose occurrence would be considered to be a breach of security. A breach of security is defined as an intolerable or undesirable operating condition, such as an inadequacy of spinning capacity, unacceptable low system voltage, transmission-line over-load or system instability. The probability of insecurity is displayed as a time function called the "security function". The general form of the security function is :

$$S(t) = \sum_{i=1}^{M} P_i(t) Q_i(t) \tag{2.3}$$

where,

$P_i(t)$	Individual probability that the system is in state i at time t,
$Q_i(t)$	Conditional probability that state i constitutes a breach of system security at time t,
M	Number of all possible system states.

The security function, $S(t)$, can be calculated and compared with a maximum tolerable insecurity or risk level to determine if and when some control action is required to maintain the risk of system insecurity at an acceptable level. The major problem in the application of this method to operating capacity assessment is that it is a time-consuming and exhaustive evaluation process particularly for a large system with many possible operating states. The literature does not show any practical application of the general method.

In an operating reserve evaluation at HLI, a breach of security can be defined to be inadequate spinning reserve capacity. In this constrained application, the security function approach, therefore, is identical to the PJM method and $S(t)$ is the unit commitment risk. The two techniques are, however, not the same when applied to operating reserve assessment in composite systems as the operating constraints and the number of states are different. This is discussed in more detail in Chapters 7 and 8.

It can be seen from the above discussion that using these methods, the system operator can make a decision regarding the required operating capacity based on the calculated risk, the forecast load and the specified risk criterion. A survey described in Reference [51] and continuous discussion within the Canadian Electrical Association indicate that no Canadian utility actively uses probabilistic techniques to assess operating reserve requirements. The two most important reasons for this lack of use are difficulty in interpreting the risk index and the minimal system operating information contained in a single risk value. These difficulties can be alleviated by including accepted deterministic considerations in the probabilistic indices, as described in the next section.

2.3 Classification of System Operating States

The control objectives of a power system are related to the level of security, and as this level decreases below an acceptable value, preventive controls must be taken to restore the system to a robust state. However, before such controls can be taken, the general system operating states should be recognized [85].

Overall power system performance can be divided into several operating states in terms of the degree to which reliability constraints are satisfied. A power system operating state framework was presented in an EPRI report [52]. This framework was modified in [74] and is illustrated in Figure 2.1. The original definitions of the system operating states in [52] are related to security constraints in composite system reliability evaluation. The constraints are directly related to the purpose behind the study. Composite system security constraints are discussed in [74]. In HLI operating reserve assessment the constraints refer only to the generation and total load demand. The operating states are redefined in [60] to make them applicable to operating reserve assessment in HLI. The redefined states are as follows.

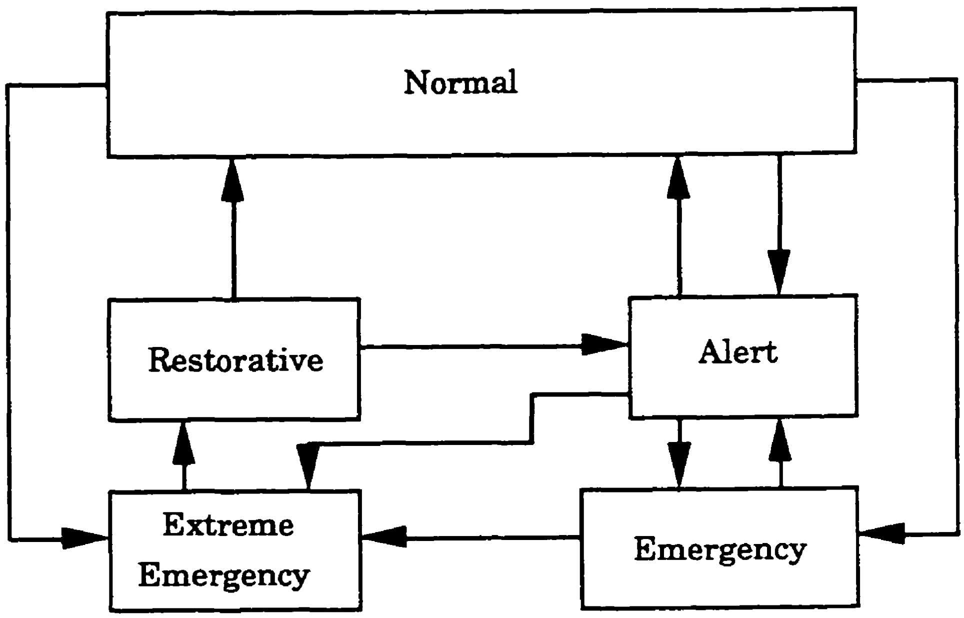

Figure 2.1: System operating state diagram.

The definition of the normal state is :

In the normal state, the generation is adequate to supply the existing total load demand. In this state, there is sufficient margin such that the loss of any generating units, specified by some criterion, will not result in load curtailment. The particular criterion, such as the loss of any single generating unit will depend on the planning and operating philosophy of the particular utility.

The specified criterion used in the research described in this thesis is that the loss of any single unit can be tolerated. It can be seen from the above definition that in the normal state, the system not only has the ability to supply the load, but also has enough reserve such that the loss of any single unit will not result in load curtailment. The deterministic criterion embedded in the normal state definition can be changed to suit the particular utility operating philosophy.

The definition of the alert state is :

If a system enters a condition where the loss of generating capacity covered by the operating criteria will result in load curtailment then the system is in the alert state. The alert state is similar to the normal state in that the constraint is satisfied, but there is no longer sufficient margin to withstand some outages. The system can enter the alert state by the outage of generation unit(s), or by growth in the system load.

The definition of the emergency state is :

If a contingency occurs or the load changes before a corrective action can be (or is) taken, the system will enter the emergency state. There is no reserve margin and no load is curtailed in the emergency state.

In this state, the operating capacity is exactly equal to the load. If control measures are not taken in time to restore the system to the alert state, the system will transfer from the emergency state to the extreme emergency state.

The definition of the extreme emergency state is :

In this state, the system constraint is violated and some portion of the system load is curtailed.

The system operator should commit additional generation into service to transfer the system from the extreme emergency state to the normal or alert state and reconnect the curtailed load through the restorative state.

For a given set of generating units and considering all possible contingencies:

$$P_n + P_a + P_{em} + P_{exem} = 1. \tag{2.4}$$

In (1), P_n , P_a , P_{em} and P_{exem} are the probabilities of the normal, alert, emergency and extreme emergency states, respectively. These probabilities can be calculated from the probabilities of the different contingencies. A contingency is defined as a combination of generating unit outages. Each contingency can be associated with one of the operating states. Once the probability of each contingency is calculated, the next step is to determine which operating state it belongs to according to the different operating state definitions.

2.4 Generating System Operating State Risk

From the system operating state definitions discussed in the previous section, it can be seen that no constraint is violated or load curtailed in either the normal or the alert state. A system operating objective is therefore to operate the system with a high probability of being in these two states. The summation of the two probabilities of the normal and the alert states provides an assessment of the favorable conditions associated with the system. The complement of the sum of these two probabilities represents the unfavorable conditions and therefore constitutes the system risk. A risk index designated as the Generating System Operating State Risk (GSOSR) can be calculated using Equations 2.5(a) and 2.5(b).

$$GSOSR = 1 - P_n - P_a \tag{2.5a}$$

or

$$GSOSR = P_{em} + P_{exem} \tag{2.5b}$$

This risk index is identical to the unit commitment risk obtained in the PJM method and can be identified as the probability that the system will fail to meet the load or just be able to meet the load for a given lead time. The GSOSR is used in this chapter as the basic system risk criterion.

2.5 System Well-being Model

The concepts of the basic probabilistic method designated as the PJM method are illustrated in detail in Section 2.2.2.1. For a given load and set of committed units, system performance can be identified using this method as being in either the comfort or at risk domains. The system operating domains are shown in Figure 2.2. In the comfort domain the operating capacity is greater than the load, whereas in the risk domain it is less than or equal to the load. In the PJM method there is no information on the degree of system comfort. Unit commitment risk and its complementary value, i.e. probability of system comfort, are the only information available to the system operator. Deterministic criteria are easier for the system operator to understand than a risk index determined using only probabilistic techniques. In order to alleviate the difficulty in interpreting the risk index and provide more applicable information for the system operator, accepted deterministic considerations can be included in the probabilistic assessment.

The main advantage of the proposed technique compared to the basic PJM method is that it combines deterministic considerations with probabilistic indices to monitor the system well-being. This combination is achieved by recognizing that the system operating states created by incorporating the system deterministic criteria can be categorized as being healthy, marginal or at risk [60]. These system operating divisions create the system well-being framework shown in Figure 2.2 and can be quantified using the system

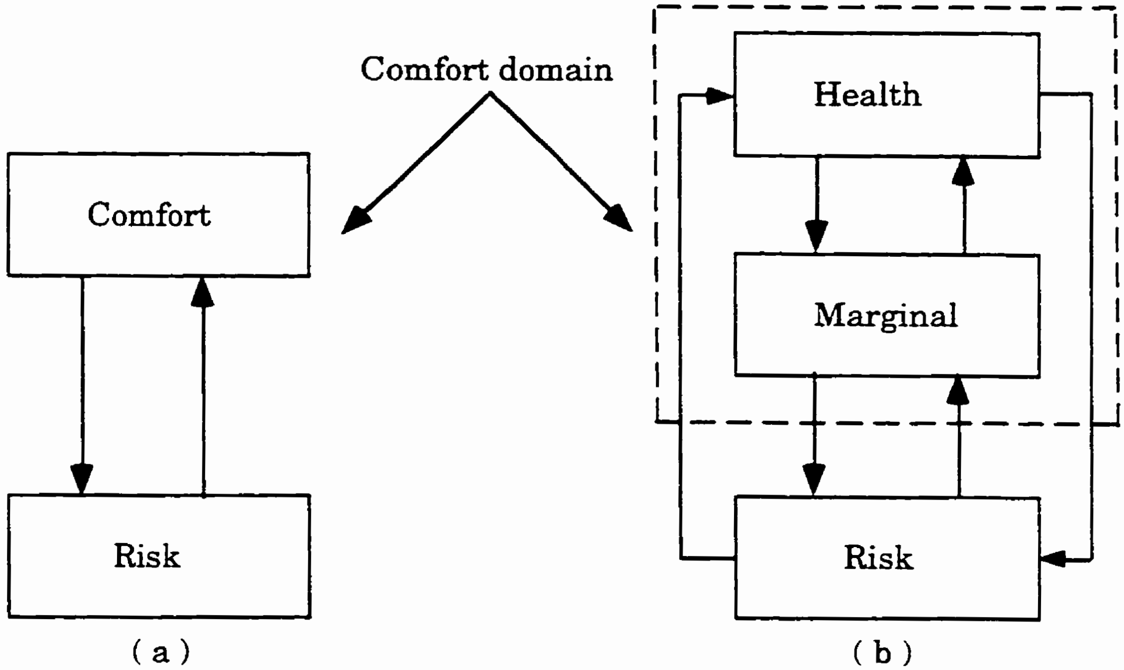

Figure 2.2: System operating domains. (a)PJM method, (b)Well-being model.

operating state probabilities. In the context of system well-being, the term healthy, marginal and at risk are substituted for normal, alert, emergency and extreme emergency [60]. A system operates in the healthy (normal) state when it has enough margin to withstand the deterministic criterion, i.e. any single unit outage. In the marginal (alert) state the system no longer has sufficient margin that it can withstand outages in excess of the specified deterministic criterion. In the at risk (emergency and extreme emergency) state the system load is greater than or equal to the operating capacity. The healthy and marginal states both reside in the comfort domain as shown in Figure 2.2 and indicate the degree of comfort. The risk domain is identical in both cases. The well-being framework is used throughout this thesis.

It can be seen from the above definitions that the proposed technique provides more information to the power system operator than the basic PJM method. The proposed state classification not only informs the operator of the system risk but also provides information on the degree of system well-being based on the accepted deterministic criterion. This cannot be achieved using the basic PJM method. The system well-being is increased by scheduling or committing additional generating unit(s). If the system operates with a high probability in the marginal state, this is a warning to the system operator to start up additional unit(s) in order to push the system into the healthy state. This warning is not available in the basic PJM method because the individual probabilities of the healthy and marginal states cannot be recognized.

2.6 Unit Commitment and Evaluation Procedure

Once an operating criterion is adopted, the goal is to satisfy the criterion throughout the various stages of system operation. The operating criterion could be an acceptable level of risk, an acceptable probability of the healthy state or both, depending on the required level of reliability. As noted earlier, the system risk is identical to the risk evaluated by the PJM method. If unit commitment is performed using a specified risk then the number of committed units and the corresponding risk will be identical to those obtained by the basic PJM method, provided that the specified risk and all other system parameters are the same. The operating criterion might be to operate the system such that the probabilities of the healthy state and the system risk state are both at acceptable levels. In this case, units should first be committed to satisfy the specified risk. The number of committed units may or may not meet the acceptable healthy state probability in which case additional unit(s) should be committed until the probability of the healthy state exceeds or equals the specified value. The required number of units therefore depends on the desired healthy state probability and the specified risk. The system health probability is an additional index which reflects the system well-being. The concept of satisfying multiple criteria provides a more comprehensive appraisal of the system well-being and therefore more comfort for the system operator who has to make the required decisions.

2.7 Description of the IEEE Reliability Test System

The single line diagram of the IEEE-RTS is shown in Figure 2.3. This 24 bus system was established by an IEEE Task Force in 1979 [89]. It is a relatively large power system in which sufficient complexity and detail have been included to make the test system representative of an actual utility system. This system has 11 generator buses, 13 load buses, 33 transmission-lines and 5 transformers. The total number of generating units is 32, ranging from 12 MW to 400 MW. The total system generation is 3405 MW and the annual peak load is 2850 MW. The generation data and the system priority loading order for the IEEE-RTS are given in Table 2.1.

2.8 Application to the IEEE Reliability Test System

The concepts described in the previous sections have been applied to the IEEE-RTS. A unit commitment schedule has been developed using a seven step load model, assuming that the system lead time is four hours.

Each generating unit is represented by a two-state model which includes an operating state and a failed state [3]. The repair process is not considered in determining the time dependent availabilities and unavailabilities of the generating units. Applying this approximation, the probability of the unit failing during a short interval of time T is [3]:

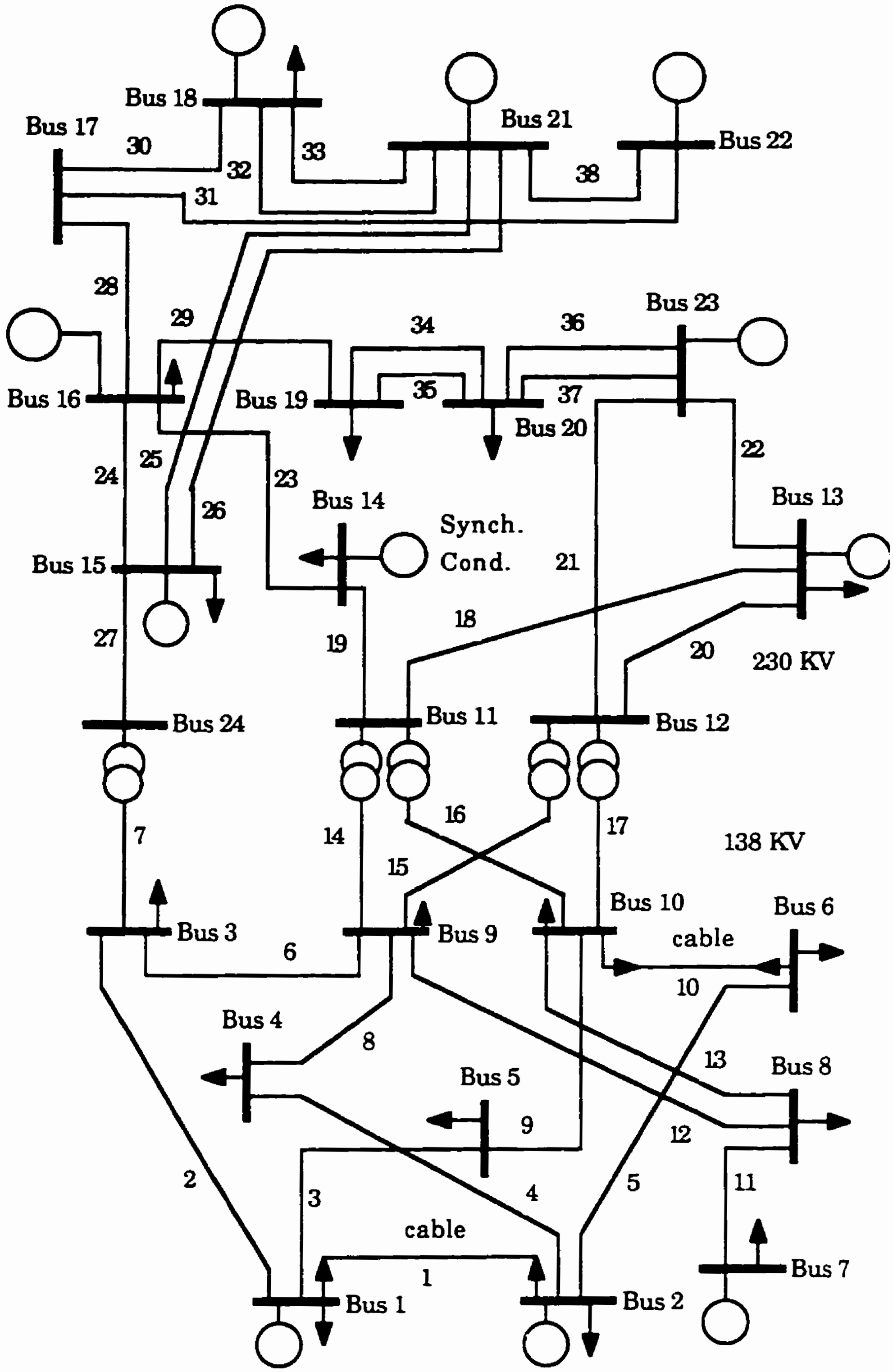

Figure 2.3: Single line diagram of the IEEE-RTS.

Table 2.1: Generating unit data for the IEEE-RTS.

Priority loading order	Unit size [MW]	Failure rate [f/yr]	Connected at Bus
1-4	50	4.42	22
5	400	7.96	18
6	400	7.96	21
7	350	7.62	23
8-10	197	9.22	13
11	155	9.13	15
12-13	155	9.13	23
14	155	9.13	16
15-17	100	7.3	7
18-19	76	4.47	1
20-21	76	4.47	2
22-26	12	2.98	15
27-28	20	19.47	1
29-30	20	19.47	2
31-32	50	4.47	22

$$P(down) = 1 - e^{-\lambda T}. \tag{2.6}$$

If $\lambda T << 1$,

$$P(down) \approx \lambda T = \text{Outage Replacement Rate} = \text{O.R.R} \tag{2.7}$$

Table 2.2 shows the required number of committed units and the corresponding probabilities of the different operating states when a specified risk of 0.01 is selected as the unit commitment criterion. It can be seen that the healthy state probability is zero for some load levels. The reason for this is that the system with the designated number of committed units and at the corresponding load level does not have sufficient spinning reserve to tolerate specific single unit outages. If an acceptable level of healthy state probability

Table 2.2: Unit commitment at a specified risk of 0.01.

Load level [MW]	No. of Units	Probability of		
		Health	Margin	Risk
1140	8	0.97719573	0.02266299	0.00014127
1425	10	0.97684725	0.02298005	0.00017271
1710	11	0	0.99260594	0.00739406
1995	13	0.95691649	0.04272104	0.00036247
2280	15	0	0.99254908	0.00745092
2565	18	0	0.99251699	0.00748301
2850	24	0	0.99228091	0.00771909

is required then the number of committed units must be increased. Table 2.3 shows the number of committed units and system operating state probabilities when the system is required to satisfy both a specified risk and a specified healthy state probability. The selection of specific values for the healthy state probability (e.g. 0.9) and risk (e.g. 0.01) depends on the desired degree of system well-being and the conditions under which the system is being operated. Assuming that the risk should be less than or equal to 0.01 and the probability of the system being in the healthy state should be greater

Table 2.3: Unit commitment at a specified risk of 0.01 and a desired healthy state probability of 0.9.

Load level [MW]	No. of units	Probability of		
		Health	Margin	Risk
1140	8	0.97719573	0.02266299	0.00014127
1425	10	0.97684725	0.02298005	0.00017271
1710	12	0.96871937	0.03104789	0.00023273
1995	13	0.95691649	0.04272104	0.00036247
2280	16	0.95424218	0.04536093	0.00039689
2565	19	0.93958229	0.05987774	0.00053997
2850	28	0.91916923	0.08011214	0.00071863

than or equal to 0.9, it can be seen from Table 2.3 that the system should commit more units in addition to the previously committed units to satisfy both criteria. In this study, the required number of units is dominated by the desired level of healthy state probability rather than the specified risk. If a single specified risk of 0.001 is selected as the criterion for unit commitment, the results will be the same as those given in Table 2.3. If a sufficiently low risk value is selected as the operating criterion, it then drives the unit commitment process and in doing so creates an acceptable healthy state probability. This is a general observation and actual values for any specific system can only be obtained by detailed analysis.

It should be appreciated that the probabilities of the healthy and marginal states cannot be calculated using a capacity outage probability table and therefore the computing time required for this method is more than that needed for the basic PJM method. In order to reduce the CPU time, the required number of generating units for a specified risk is first determined using a capacity outage table. The system operating state probabilities are then calculated for the committed units by classifying contingency states, as explained earlier. If a specified healthy state probability is not satisfied, it is obtained in a second step by adding further generating units.

The required number of units and the probabilities associated with the system operating states depend on many factors such as system lead time, system load, generating unit failure rates and the acceptable risk level [60]. System lead time is one of the most important factors in the assessment of unit commitment. In the results presented in Tables 2.2 and 2.3 , it is assumed that the system lead time is fixed at 4 hours. The number of committed units, system operating state probabilities and corresponding risk for a load level of 1995 MW, i.e. 70% of the peak load of 2850 MW, are shown in Table 2.4. The system lead time was varied from 0.5 hour to 15 hours and the unit commitment made using a specified risk value of 0.001. In actual practice, the load will not remain constant at the specified level and units will be added and removed to meet the forecast demand [3]. The number of committed units for this range of lead times varies from 13 to 15. With this commitment schedule, the system is not only able to satisfy the specified risk of 0.001 but also satisfies a healthy state probability of 0.9 even though this value was not used as a unit commitment criterion.

Table 2.4: Unit commitment and system operating state probabilities for different lead times.

Lead time [hr]	No. of Units	Probability of		
		Health	Margin	Risk
0.5	13	0.99451896	0.00547531	0.00000573
1	13	0.98906549	0.01091162	0.00002288
2	13	0.97824074	0.02166803	0.00009123
3	13	0.96752474	0.03227069	0.00020458
4	13	0.95691649	0.04272104	0.00036247
5	13	0.94641501	0.05302054	0.00056446
10	14	0.94158662	0.05756545	0.00084793
15	15	0.95496327	0.04430710	0.00072963

2.9 Conclusions

An approach to operating reserve assessment is illustrated in this chapter using system operating states. The state definitions permit the inclusion of the deterministic criteria used by most operating utilities. Operating system health, margin and risk are designated and defined using the system operating states. The technique provides the opportunity for the system operator to quantify the degree of system well-being in addition to the system risk. This quantification cannot be achieved using the basic PJM method. The conventional risk index is designated as the GSOSR and defined as the probability of residing in an undesirable system operating state. Generating units can be committed to the system at a particular load level in order to satisfy a specified risk or a specified probability of the system being in the healthy state. The application of the proposed technique is illustrated using the IEEE-RTS. The study results presented illustrate the effect of variations in the operating criteria and the system lead time on the required number of units and system operating state probabilities.

Operating reserve evaluation involves two distinctly different aspects of unit commitment, in which the system operator decides which units and how many should be committed to satisfy the operating criteria and the dispatch decisions regarding those units that have been committed [3]. Both sets of studies are necessary to obtain a complete picture of operating reserve assessment, i.e. these studies complement rather than substitute for each other. The second aspect is discussed in the next two chapters.

3. SPINNING RESERVE ALLOCATION USING RESPONSE HEALTH ANALYSIS

3.1 Introduction

Operating reserve provides an electric power system with the ability to respond to unforeseen load changes and sudden generation outages and a wide range of techniques have been used to determine operating reserve requirements. Operating reserve evaluation involves two distinctly different aspects. The first is unit commitment, in which the system operator decides which units should be committed to satisfy the operating criteria. The second aspect is associated with unit dispatch decisions and the evaluation of response capability of the committed units [3]. Both aspects are necessary to obtain a complete appraisal of the operating reserve requirement, i.e. these activities complement rather than substitute for each other. The probabilistic technique developed for unit commitment and assessment of generating system operating health, margin and risk in [60] is briefly discussed in Chapter 2. The operating state probabilities are calculated in this approach based on the total amount of spinning reserve in the system, where spinning reserve is defined as the difference between the total operating capacity and the system load. The utility of this reserve depends on many factors of which the response rate of the committed units and the location of the spinning reserve are the most important [90]. An assigned amount of the spinning reserve must be available within a given period of time in the event of a sudden loss of generating capacity, unforeseen changes in the system load or any other contingency which results in loss of capacity [55,91-100]. Most utilities use a fixed percentage of their spinning reserve as the required response within a specified period of time. This percentage and the time period varies from system to system [51].

The operating state framework proposed in [52] was examined in [60] for application to unit commitment in a generating system and is discussed in Chapter 2. This framework is further modified and redefined in this chapter to evaluate the response capability of a generating system within a given period of time and is referred to as the response state framework. A risk index designated as the Generating System Response State Risk (GSRSR) is used as the criterion for loading the committed units. This chapter illustrates the evaluation of the degree of system well-being in responding capability of the committed units. The overall well-being of a generation system in terms of its responding capability is identified as being healthy, marginal and at risk. Once the number of committed units is determined, the spinning reserve should be allocated among the committed units to satisfy the response criterion. This criterion could be a specified GSRSR, an acceptable response health probability or both [101]. The operating cost, however, varies with different response criteria. An algorithm is developed in this chapter to determine the required number of units and optimal load dispatch of the committed units based on the unit commitment and response criteria. The developed concepts are illustrated in this chapter by application to the IEEE-RTS.

3.2 Spinning Reserve Allocation in a Power System

Unit commitment involves determining which units should operate in order to supply a particular load level while satisfying a stated operating criterion as discussed in Chapter 2. The question that is not answered in this analysis is as follows: Given that there are a number of subsets of the power outputs of a complete set of N committed generating units which would satisfy the unit commitment criteria, which of these subsets should be used in order to provide the minimum operating cost as well as an acceptable level of reliability. In other words, the unit commitment analysis does not indicate how these committed units should be dispatched, i.e. which unit and how much of each unit should generate power or be held as spinning reserve. It is, therefore, obvious that the difference between the operating capacity and the load is not a valid indicator of the ability of the system to respond to a loss of capacity.

Spinning reserve represents the unloaded generating capacity of a unit and in unit commitment assessment it is defined as reserve which is synchronized and immediately ready to pick up load [3]. Unit commitment is based on this assumption and the system health, margin and risk probabilities are directly related to the amount of spinning reserve. In a practical power system, the reserve cannot be utilized instantaneously and is restricted by the ramp rate characteristics of the committed generating units. A system may have a large amount of spinning reserve at a particular generation/load condition but the actual responding capability may be quite inadequate for reliable system operation. An assigned amount of spinning reserve must be available within a given time period to provide protection in the event of a sudden loss of generating capacity, an unanticipated load change or any other power system disturbance. This time period is referred to as the margin time (MT) and its actual value may vary from system to system. The margin time is defined as the time required to make necessary changes in generating unit output. The available generation change that can be achieved within a margin time is known as the regulating margin [58]. The margin time and the regulating margin are the two most important parameters in evaluating the response capability of a generation system.

Different utilities have different policies regarding the amount of required responsive reserve and the margin time. Table 3.1 shows the load pickup periods and the associated required regulating margin (RRM), as a percent of operating reserve, employed by some Canadian electric power utilities. This summary is based on surveys conducted by the CEA Power System Reliability Subsection [51].

Table 3.1: Utility margin times and required regulating margins.

Utility	Period A		Period B		Period C	
	RRM [%]	MT [min.]	RRM [%]	MT [min.]	RRM [%]	MT [min.]
AIS	100	10	-	-	-	-
HQ	33	*	33	10	33	30
N.B.P	38	5	38	10	24	30
OH	67	10	33	30	-	-

*: As the response of hydro units.
AIS: Alberta Interconnected System,
HQ: Hydro-Quebec,
N.B.P: The New Brunswick Electric Power Commission,
OH: Ontario Hydro,
RRM: Required Regulating Margin as a percent of operating reserve.

3.3 Response Model Description

The operating state framework proposed in [52] is modified and examined in this chapter to evaluate the response capability of a generating system and is illustrated in Figure 3.1(a). The overall well-being of a generating system in terms of its responding capability is identified as being healthy, marginal and at risk in Figure 3.1(b). The state definitions are based on the security constraints which depend on the purpose behind the study. In unit commitment assessment, the security constraint is that the total maximum capacity of the committed units must be greater than the system load. The state definitions based on unit commitment are given in Chapter 2. In the assessment of response capability, the constraint is that the total available response capacity of the committed units within a certain margin time must be greater than the required regulating margin. The definitions of the system response healthy, marginal and risk states are as follows.

The definition of the healthy state is :

In the healthy state, the spinning reserve is allocated among the committed generators such that the available responding capacity is adequate to satisfy the response requirements within the margin time. In this state there is sufficient response capability such that the loss of any generating units, specified by some operating criteria, can be responded to within the margin time, without requiring load curtailment or committing additional unit(s).

The particular criterion such as the loss of any single generating unit and also the amount of required regulating margin will depend on the operating philosophy of the particular utility. The required regulating margin within the margin time varies from system to system and may be a certain percentage of the spinning reserve.

The definition of the marginal state is :

The marginal state is similar to the healthy state in that the required regulating margin is met, but there is no longer sufficient response capacity to pick up the curtailed load due to the loss of some single generating unit outages. The system can transfer to the healthy state by making the necessary changes in the load dispatch or by starting up additional unit(s).

The definition of the risk state is :

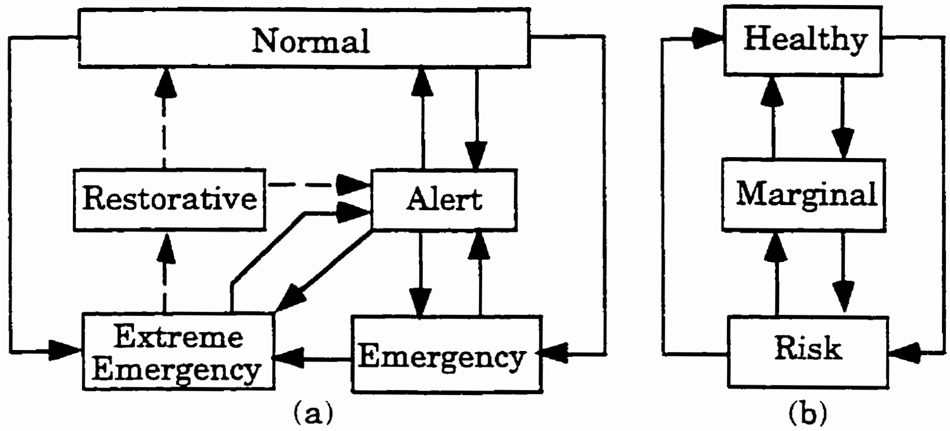

Figure 3.1: Diagram of (a)system response states, (b)system response well-being.

If a contingency occurs or the load changes before a corrective action can be(is) taken, the system will enter the risk state. In this state, the amount of responding generation is equal or less than the required regulating margin. If control measures such as changes in the load dispatch or starting up additional unit(s) are taken the system will be restored to the marginal state.

It can be seen from the state definitions that the security constraints are within limits in both the healthy and marginal states. The response state probabilities are calculated using contingency enumeration of the committed units. A contingency is defined as a combination of generating unit outages. Considering all contingencies,

$$P_h^r + P_m^r + P_r^r = 1, \tag{3.1}$$

where P_h^r, P_m^r and P_r^r are the probabilities of the response healthy, marginal and at risk states, respectively. The Generating System Response State Risk (GSRSR) is defined as shown in Equation (3.2):

$$GSRSR = 1 - P_h^r - P_m^r. \tag{3.2}$$

The system operating objective should be to operate the system with high probability of being in either the healthy or marginal state from both a unit commitment and a response point of view. A system at a particular load level with a high unit commitment healthy state probability, may not have a high response healthy state probability depending on how the spinning reserve is allocated. Such a system does, however, have the potential ability to have a high response healthy state probability depending on the margin time. Having a high marginal state probability is a warning to the system operator to adjust unit loadings to transfer the system from the marginal to the response healthy state.

3.4 Load Dispatch With Response Criterion

The load dispatch task is to assign the system demand to the committed generating units. Starting from an economic load dispatch [25], the unit loadings are adjusted by moving in the direction required to satisfy the response criterion. This criterion could be a specified GSRSR, an acceptable response health probability or both. The load dispatch for which the response criterion is satisfied is referred to as the optimum load dispatch. The selection of the specified GSRSR and response health probability depends on the system operating philosophy, the desired level of reliability, the corresponding cost and the optimum benefit.

The system response state probabilities can be calculated by simulating all possible contingencies for the set of committed units. Each contingency event causes the system to reside in one of the response states based on the accepted definitions. Out of the total possible contingencies, most of them cause the system to be in the risk state and only a few are associated with the healthy and marginal states. Evaluation can require a considerable computation time particularly for systems with a large number of committed units. In order to overcome this difficulty, the GSRSR is first determined for each load dispatch using a capacity outage probability table (COPT). The COPT is obtained by combining all the committed units. The unit capacity C_i is given in Equation 3.3.

$$C_i = L_i + AR_i \tag{3.3}$$

where

$$AR_i = Min[(G_i - L_i), RC_i] \text{ , and} \tag{3.4}$$

$$RC_i = RR_i \times MT . \tag{3.5}$$

L_i	Loading of unit i in the considered load dispatch,
G_i	Maximum capacity of unit i,
RR_i	Response rate of unit i,
AR_i	Actual response output of the ith unit in MW,
RC_i	Response capability of the i_{th} unit in MW.

Each unit is represented by a two-state model as shown in Figure 3.2. This is the simplest possible generating unit model and assumes that the unit resides in either the up state or the down state. The parameter λ (failure rate) is the state transition rate from the up state to the down state. The GSRSR for n committed units and at a margin time of MT can be expressed as;

$$GSRSR = \sum_{j=1}^{NC} P_j(MT) \times Q_j(MT). \tag{3.6}$$

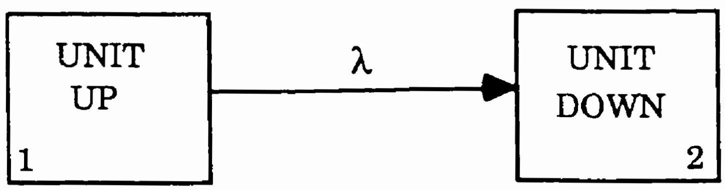

Figure 3.2: Simplified two-state model used in operating reserve evaluation.

Where,

$NC = 2^n$ Total number of possible contingencies for n two-state model units and

$P_j(MT)$ Probability of contingency j occurring at margin time of MT,

$$Q_j(MT) = \begin{cases} 0 & when \quad Load + RRM < CAP_j \\ 1 & when \quad Load + RRM \geq CAP_j \end{cases} \tag{3.7}$$

Where RRM is the required regulating margin and CAP_j is the total capacity available with contingency j. For contingency j, where m units are in service and $n-m$ units are out of service, CAP_j is calculated using Equation 3.8.

$$CAP_j = \sum_{i \in m} C_i \tag{3.8}$$

By arranging the COPT in descending order, i.e. $CAP_j > CAP_{j+1}$ for $j = 1, 2, \ldots, NC-1$, Equation 3.6 is modified as:

$$GSRSR = \sum_{j=k}^{NC} P_j(MT). \tag{3.9}$$

Where k is an integer such that $CAP_{k-1} > LOAD + RRM \geq CAP_k$. If ARR is the acceptable response risk, then the GSRSR should be such that;

$$GSRSR < ARR. \tag{3.10}$$

If the GSRSR is not satisfied, the load dispatch must be adjusted. The first step in reloading the units is to divide the dispatched units into three groups in which their spinning reserve $(G_i - L_i)$ is equal, less than or greater than their response capability (RC_i) as expressed below [102,103].

$$\begin{cases} G_i - L_i = RC_i & Group\ I \\ G_j - L_j < RC_j & Group\ II \\ G_k - L_k > RC_k & Group\ III \end{cases} \tag{3.11}$$

The goal here is to increase the actual response output of those units whose spinning reserves are more than their response capabilities. In order to achieve this goal, the unit in Group II whose incremental running cost is the highest and the unit in Group III whose incremental running cost is the lowest must be identified. Once these two units are found, an incremental load is taken away from the unit in Group II and given to the unit in Group III. The incremental running cost can be obtained using a basic economic dispatch formulation. The simplified cost model of the i_{th} unit F_i is expressed [104,105] as shown in Equation 3.12 where P_i is the power output and A_i, B_i and C_i are the cost parameters of the i_{th} unit.

$$F_i = A_i + B_i \times P_i + C_i \times P_i^2 \tag{3.12}$$

The total fuel cost F_t before reloading the units is given by Equation 3.13.

$$F_t = \sum_{i=1}^{n} F_i(P_i) \tag{3.13}$$

The incremental running cost of unit k for an increasing load of ΔP and that of unit j for a decreasing load of ΔP are shown in Equations 3.14 and 3.15 respectively.

$$\Delta F_k = \Delta P[B_k + C_k(2P_k + \Delta P)] \tag{3.14}$$

$$\Delta F_j = \Delta P[B_j + C_j(2P_j - \Delta P)] \tag{3.15}$$

The total running cost increases by $(\Delta F_k - \Delta F_j)$.

This procedure is continued until the GSRSR is satisfied. Once the GSRSR is satisfied, the system response health and margin probabilities are calculated by considering each contingency individually. Each contingency must be evaluated to determine which response state it belongs to according to the different response state definitions. For the case of multiple response criteria, adjustments of the unit loadings must be continued until a specified response health probability is satisfied. The reserve in the system can be in the form of spinning reserve, stand-by reserve, interruptible load or assistance from interconnected systems. In the above procedure, the reserve in the system is considered to be in the form of spinning reserve. The method can also be extended to include stand-by equipment and other types of reserve. The proposed approach is summarized in the flowchart shown in Figure 3.3. In some cases, a system cannot satisfy the response criteria even after adjusting the units. In these cases, the procedure can be continued by committing one more unit as shown by the dashed lines in the flowchart.

3.5 Application to the IEEE Reliability Test System

The concepts developed in the previous sections have been applied to the IEEE-RTS. The generating unit data and the associated cost parameters are shown in Table 3.2. The basic results for unit commitment in the IEEE-RTS

Table 3.2: Generation unit and cost data for the IEEE-RTS.

Priority order	$P_{max.}$ [MW]	$P_{min.}$ [MW]	RR*	λ f/Yr	Cost parameter A	B	C
1-4	50	0	10	4.42	0	0.5	0
5-6	400	200	0	7.96	216.576	5.345	0.00028
7	350	150	9	7.62	388.250	8.919	0.00392
8-10	197	80	6	9.22	301.223	20.023	0.00300
11-14	155	60	5	9.13	206.703	9.2706	0.00667
15-17	100	40	3	7.3	286.241	17.924	0.00220
18-21	76	25	2	4.47	100.439	12.145	0.01131
22-26	12	5	1	2.98	30.396	23.278	0.13733
27-30	20	6	4	19.47	40	37.554	0.18256
31-32	50	0	10	4.47	0	0.5	0

*RR= Response Rate in MW/min.

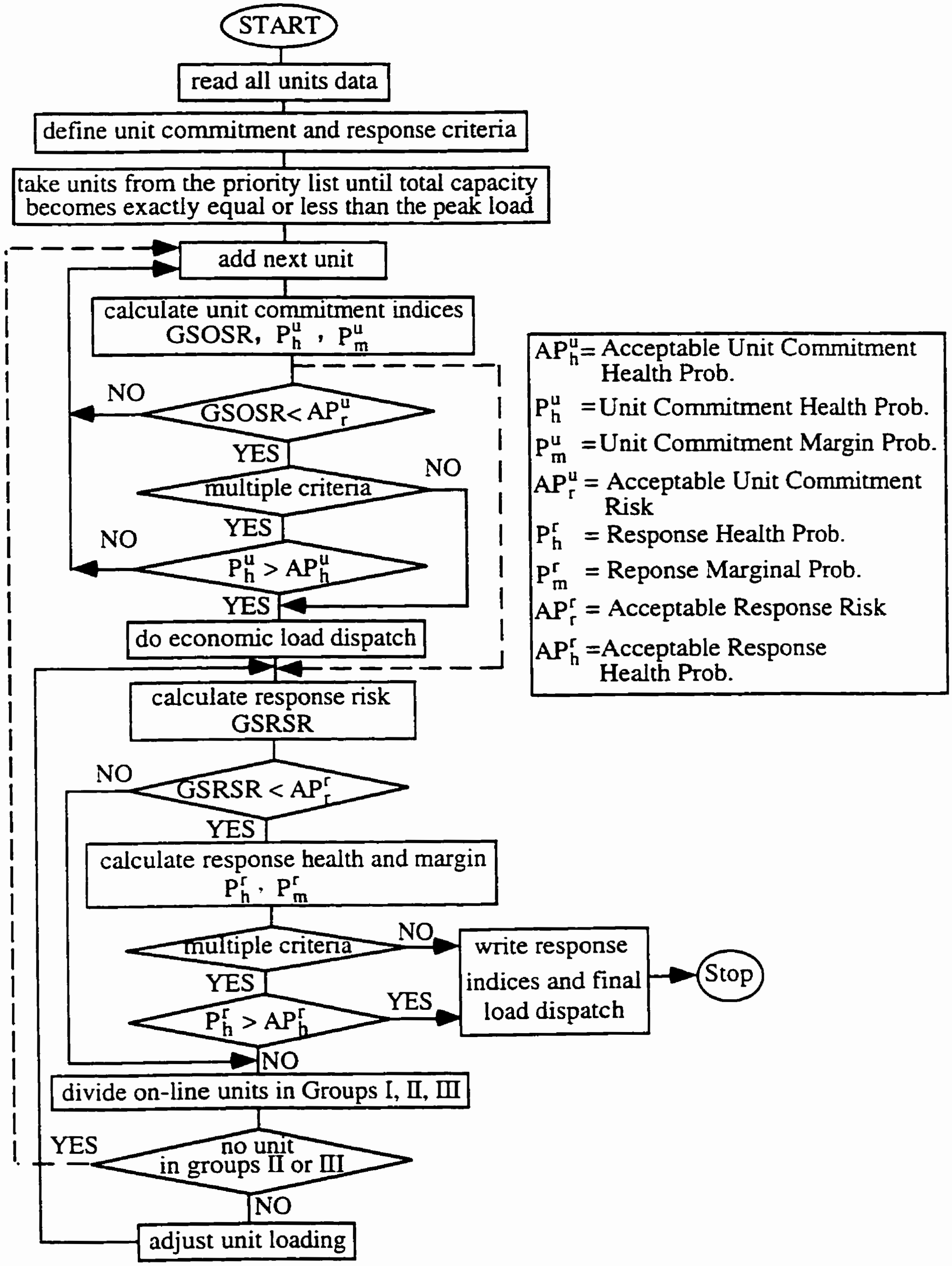

Figure 3.3. Flowchart of unit commitment and response health analysis.

are given in Chapter 2. In these studies, two different cases are considered in which the required number of committed units for single or multiple criteria are determined.

3.5.1 Basic Results

Consider that unit commitment is done for the IEEE-RTS at a load level of 70% of the peak load of 2850 MW, i.e. 1995 MW. The system lead time is assumed to be 4 hours and a specified risk of 0.01 is selected as the unit commitment criterion. The number of committed units is 13 and the system operating health, margin and risk probabilities are 0.95691649, 0.04272104 and 0.00036247 respectively. The total spinning reserve is 411 MW. The system with this number of committed units has a high healthy state probability based on a unit commitment point of view. It may or may not be in the healthy state in terms of system responding capability as that is extremely dependent on how the spinning reserve is distributed among the committed units. Only 240 MW of the total 411 MW spinning reserve is available within a margin time of 10 minutes based on the economic load dispatch for which the total operating cost is $19381.1/hr. Using the procedure described in the previous section, the generating units are reloaded to provide more response capability. A discrete load change of 1 MW was used to obtain the loading schedules. The response capability, therefore, changes with each step of 1 MW. The results are more accurate when a small discrete load change is used than when a large value is used. The computation time, however, increases when the reloading incremental value is decreased. The variation in power outputs of the committed units and the total operating cost versus the system response are shown in Figure 3.4. The first 6 units are at their maximum capacity. Their outputs do not change through the reloading

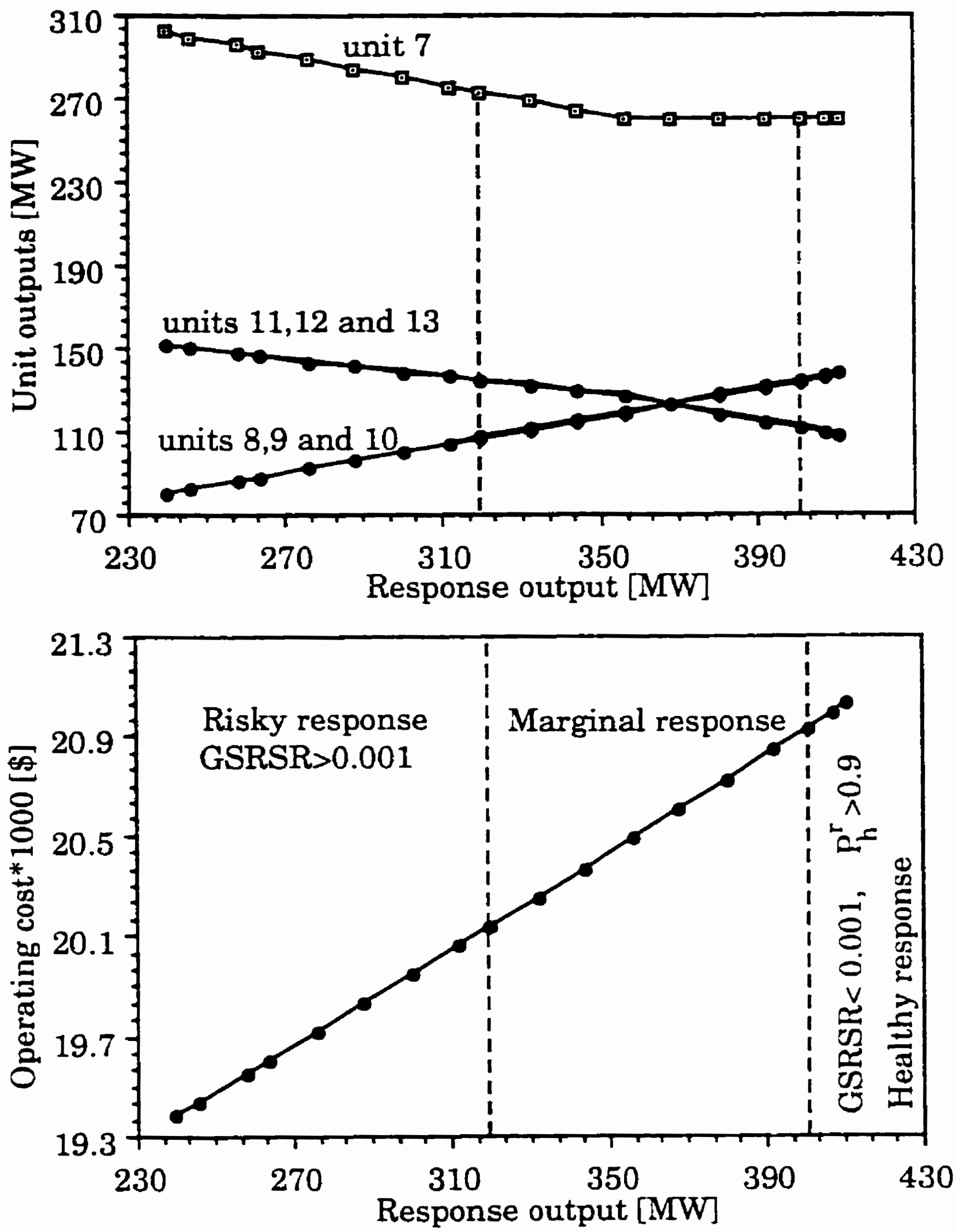

Figure 3.4: Unit outputs and operating cost versus response.

steps and are not shown in Figure 3.4. The operating costs of these units, however, are included in the total operating cost. The system response health, margin and risk probabilities were calculated using the developed procedure.

Consider a required regulating margin of 40% of the spinning reserve, i.e. 164 MW, and an acceptable GSRSR of 0.001. For the case of economic load dispatch, the system response risk is 0.0014943 which is greater than 0.001. In order to satisfy the acceptable GSRSR of 0.001, the system requires that a response output of 320 MW become available within the margin time of 10 minutes. Figure 3.4 shows a vertical line at a response output of 320 MW and the optimum load dispatch for this condition. Under these circumstances, the system response health, margin and risk probabilities are 0.0, 0.999026 and 0.000974 respectively. All different load dispatches on the right hand side of this line meet the response criterion but this point has the cheapest cost, i.e. $20,133.9. The second vertical line is the optimum load dispatch if the system is required to satisfy a specified response healthy state probability of 0.9 in addition to satisfying an acceptable response risk of 0.001. At this load dispatch, the total response output is 401 MW and the system operating cost is $20,929.3. The system response health, margin and risk probabilities under this condition are 0.99816992, 0.00138165 and 0.00044844 respectively. This system could have a total response output of 411 MW within the margin time, but the system operating cost would increase to $21,030.3/hr.

Table 3.3 shows the response health, margin and risk probabilities for seven load steps of the IEEE-RTS at the economic load dispatch obtained by dynamic programming. The unit commitment has been done such that the system with the designated number of committed units and for the

Table 3.3: Response indices for economic load dispatch.

Load MW	No. of units	RRM MW	SR MW	Probability of response			RM MW
				Health	Margin	GSRSR	
1140	8	162	407	0	0	1	150
1425	10	206	516	0	0.9990262	0.0009738	270
1710	12	216	541	0	0.9986792	0.0013208	350
1995	13	164	411	0	0.9985057	0.0014943	240
2280	16	192	481	0	0.9980550	0.0019450	250
2565	19	179	448	0	0.9983319	0.0016681	270
2850	28	166	415	0	0.9990244	0.0009756	333

corresponding load level satisfies the unit commitment healthy state probability of 0.9 in addition to satisfying a specified risk of 0.001. The required regulating margin (RRM) is assumed to be the integer value of 40% of the spinning reserve (SR) at each load level and the margin time is 10 minutes. From the results shown in Table 3.3, it can be seen that the system has high response risk at some load levels due to inadequate response capacity. The spinning reserve has to be allocated among the committed units to provide more response within the margin time. Table 3.4 shows the response indices when the system with the designated number of committed units and at the corresponding load level has to satisfy an acceptable GSRSR of 0.001. The results show that the response healthy state probability is zero for all load levels even though the spinning reserve provides a unit commitment healthy state probability in excess of 0.9 for all load levels (Table 2.3). The reason for this is that the system with the available regulating margin (RM) cannot respond within the margin time to certain specific single unit outages. Most of the spinning reserve is allocated among the thermal units which have lower response rates. The hydro units which have higher response outputs are almost fully loaded. The economic reallocation of the

Table 3.4: Response indices with single criterion.

Load MW	No. of units	RRM MW	SR MW	Probability of response			RM MW
				Health	Margin	GSRSR	
1140	8	162	407	0	0.9990407	0.0009593	163
1425	10	206	516	0	0.9990262	0.0009738	270
1710	12	216	541	0	0.9992047	0.0007953	357
1995	13	164	411	0	0.9990260	0.0009740	320
2280	16	192	481	0	0.9990256	0.0009744	348
2565	19	179	448	0	0.9990253	0.0009747	335
2850	28	166	415	0	0.9990244	0.0009756	333

generating units in order to maintain a sufficient responsive reserve margin can be done using the procedure explained in the previous section.

Table 3.5 shows the results when the system is required to satisfy an acceptable response healthy state probability of 0.9 in addition to satisfying an acceptable response risk of 0.001. The margin time is assumed to be 10 minutes. The available response capability is higher when the system must satisfy multiple criteria than when the system is required to satisfy only a single risk criterion as shown in Figure 3.5. The system operating cost also increases as illustrated in Figure 3.5. It should be noted that the system cannot satisfy an acceptable response health probability of 0.9 at the load level of 1140 MW with 8 units. Only 350 MW of the total spinning reserve of 407 MW is available within 10 minutes. This is the maximum available response within the margin time and cannot be increased by adjusting the units. One more unit must be committed, and with 9 units the response criteria are satisfied. It should also be noted that if the number of committed units are such that the system has a high margin state probability based on unit commitment, it can never have a high response healthy state probability because of insufficient spinning reserve. Having a high response margin state

Table 3.5: Response indices with multiple criteria.

Load MW	No. of units	RRM MW	SR MW	Probability of response Health	Margin	GSRSR	RM MW
1140	8	162	407	0	0.9995521	0.0004479	350
1425	10	206	516	0.9986903	0.0008617	0.0004480	401
1710	12	216	541	0.9983433	0.0012083	0.0004484	401
1995	13	164	411	0.9981699	0.0013817	0.0004484	401
2280	16	192	481	0.9977193	0.0018317	0.0004490	401
2565	19	179	448	0.9974111	0.0021396	0.0004493	401
2850	28	166	415	0.9962203	0.0033304	0.0004493	401

probability is a warning to system operators to adjust the unit loadings to provide more response capability and push the system to the response healthy state. The available response capability is higher when the system should satisfy multiple criteria than when the system is required to satisfy only a single risk criterion. The system health probability is an additional index which reflects the system well-being. The idea of satisfying multiple criteria gives more information to the system operator and a more physical approach to unit commitment and load dispatch [60,101].

Tables 3.6, 3.7 and 3.8 show the individual unit loadings for the three load dispatch cases. The regulating margin and the total operating cost for each case are shown in Figure 3.5. It should be noted that the unit commitment health, margin and risk probabilities are identical for all three cases. The required number of steps to reload from the optimum economic load dispatch and the system response health, margin and risk probabilities depend on many factors such as the number of committed units, the unit response rates, the unit failure rates, the required regulating margin, the margin time and the load forecast uncertainty. The effects of some of these

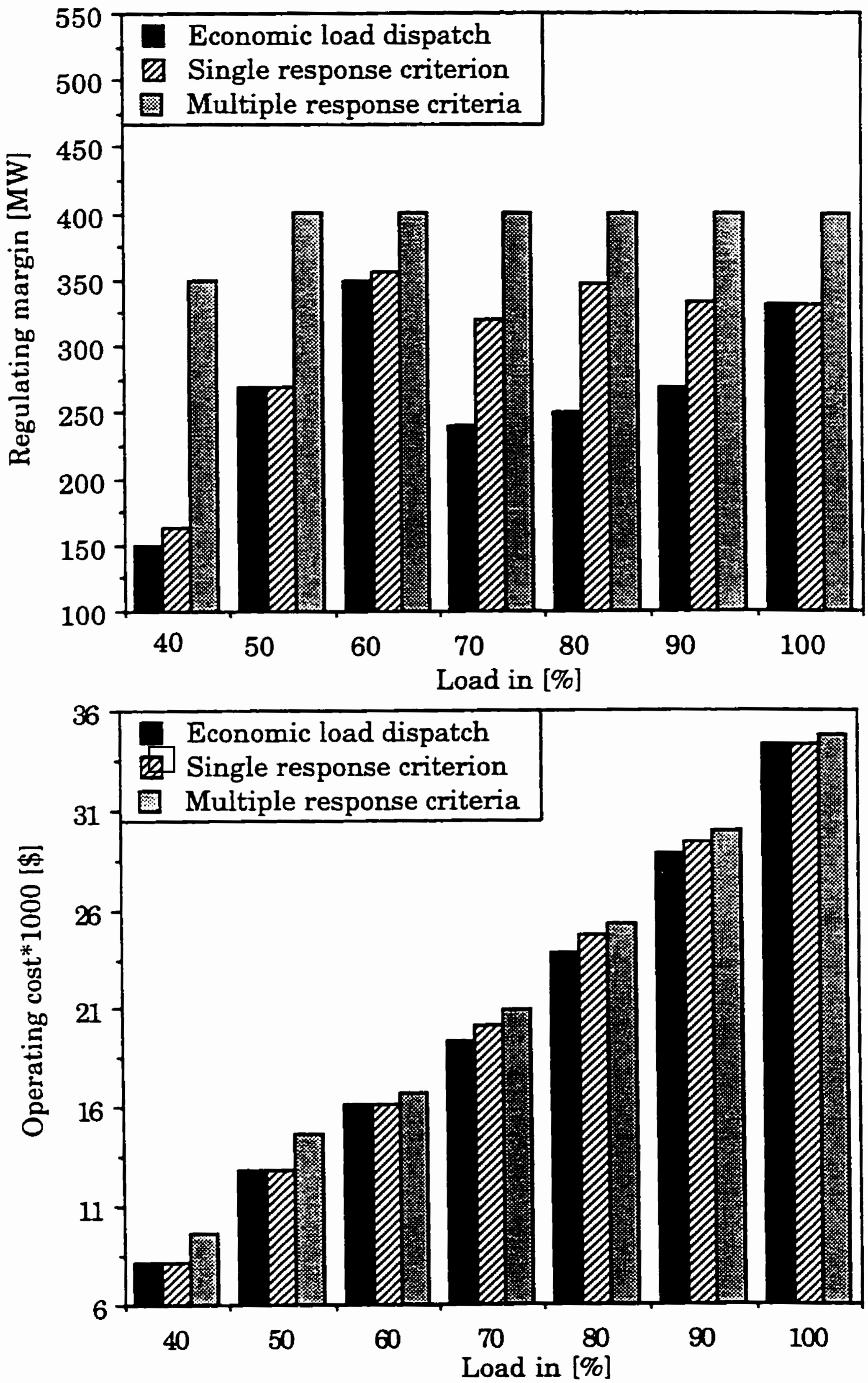

Figure 3.5: Variation in regulating margin and system operating cost.

Table 3.6: Economic load dispatch.

Load	U1	U2	U3	U4	U5	U6	U7	U8	U9	U10	U11	U12	U13	U14	U15	U16	U17	U18	U19	U20	U21	U22	U23	U24	U25	U26	U27	U28
1140	50	50	50	50	355	355	150	80																				
1425	50	50	50	50	400	400	185	80	80	80																		
1710	50	50	50	50	400	400	240	80	80	80	115	115																
1995	50	50	50	50	400	400	302	80	80	80	151	151	151															
2280	50	50	50	50	400	400	340	80	80	80	155	155	155	155	40	40												
2565	50	50	50	50	400	400	350	87	88	88	155	155	155	155	60	60	60	76	76									
2850	50	50	50	50	400	400	350	116	116	116	155	155	155	155	63	64	64	76	76	76	76	5	5	5	5	5	6	6

Table 3.7: Load dispatch with single response criterion.

Load	U1	U2	U3	U4	U5	U6	U7	U8	U9	U10	U11	U12	U13	U14	U15	U16	U17	U18	U19	U20	U21	U22	U23	U24	U25	U26	U27	U28
1140	37	50	50	50	362	361	150	80																				
1425	50	50	50	50	400	400	185	80	80	80																		
1710	50	50	50	50	400	400	247	80	80	80	111	112																
1995	50	50	50	50	400	400	273	107	107	106	134	134	134															
2280	50	50	50	50	400	400	289	99	99	98	143	143	143	144	61	61												
2565	50	50	50	50	400	400	325	108	107	107	155	155	155	155	62	62	62	56	56									
2850	50	50	50	50	400	400	350	116	116	116	155	155	155	155	63	64	64	76	76	76	76	5	5	5	5	5	6	6

Table 3.8: Load dispatch with multiple response criteria

Load	U1	U2	U3	U4	U5	U6	U7	U8	U9	U10	U11	U12	U13	U14	U15	U16	U17	U18	U19	U20	U21	U22	U23	U24	U25	U26	U27	U28
1140	0	0	0	0	400	400	260	80																				
1425	0	0	19	50	400	400	260	99	99	98																		
1710	19	50	50	50	400	400	260	91	90	90	105	105																
1995	50	50	50	50	400	400	260	134	134	133	111	111	112															
2280	50	50	50	50	400	400	273	115	115	115	134	134	134	134	63	63												
2565	50	50	50	50	400	400	294	127	126	126	146	146	146	147	65	65	65	56	56									
2850	50	50	50	50	400	400	350	137	136	136	155	155	155	155	66	66	66	59	59	59	59	5	5	5	5	5	6	6

U=Unit
Load in MW

factors on the GSRSR, the system operating well-being and the operating cost are illustrated in the following subsections.

3.5.2 Effect of Required Regulating Margin

Regulating margin (RM) is the available response output of the committed units for a given dispatch within a certain margin time. The required regulating margin (RRM) is usually expressed as a percent of the total operating reserve and varies from system to system. In the studies presented in this section, the margin time is fixed at 10 minutes and the RRM varies from 10% to 60% of the total spinning reserve. Table 3.9 presents the response indices associated with the economic load dispatch of 13 units at the load level of 1995 MW. The GSRSR increases as the RRM increases and varies from 0.00044843 to 1 as the RRM is increased from 10% to 60% of the total spinning reserve of 411 MW. A specified GSRSR of 0.001 can be satisfied at the economic load dispatch if the RRM is less than 20% of the spinning reserve.

Table 3.9: Response indices for various RRM.

Load MW	RRM [%]	RRM MW	cost [$]	Probability of response Health	Margin	GSRSR	RM MW
1995	10	41	19381.05	0	0.9995516	0.0004484	240
1995	20	82	19381.05	0	0.9995514	0.0004486	240
1995	40	164	19381.05	0	0.9985057	0.0014943	240
1995	50	205	19381.05	0	0.9981699	0.0018301	240
1995	60	246	19381.05	0	0	1	240

3.5.3 Effect of Margin Time

The margin time is one of the most important factors which influence the system response well-being. Consider a system peak load of 1995 MW and 13 committed units. The required regulating margin is assumed to be 40% of the system spinning reserve, i.e. 163 MW. The load dispatch has to be such that a specified GSRSR of 0.001 and an acceptable response health probability of 0.9 must be satisfied. The response health, margin and risk probabilities are calculated for various margin times and are presented in Figure 3.6. It can be seen from the results that the response health probability decreases as the margin time increases. The response margin and risk probabilities, however, increase as the margin time increases. The optimum load dispatch varies for different margin times. Table 3.10 shows the load dispatch for the three margin times of 5, 10 and 15 minutes. The operating cost is calculated using Equation 3.12 .

The operating cost decreases as the margin time increases as illustrated in Figure 3.7. The reason for this is that for small margin times most of the response is provided by the hydro units which are cheaper and have higher response rates. For larger margin times, the response output is mostly provided by slow responding expensive units and the lower cost hydro units are more fully loaded.

Table 3.10: Load dispatch for different margin times.

MT	cost [$]	U1	U2	U3	U4	U5	U6	U7	U8	U9	U10	U11	U12	U13
5	23826.5	0	0	0	9	400	400	305	164	163	130	130	130	130
10	20929.3	50	50	50	50	400	400	260	134	134	133	111	111	112
15	20047.6	50	50	50	50	400	400	276	104	104	103	136	136	136

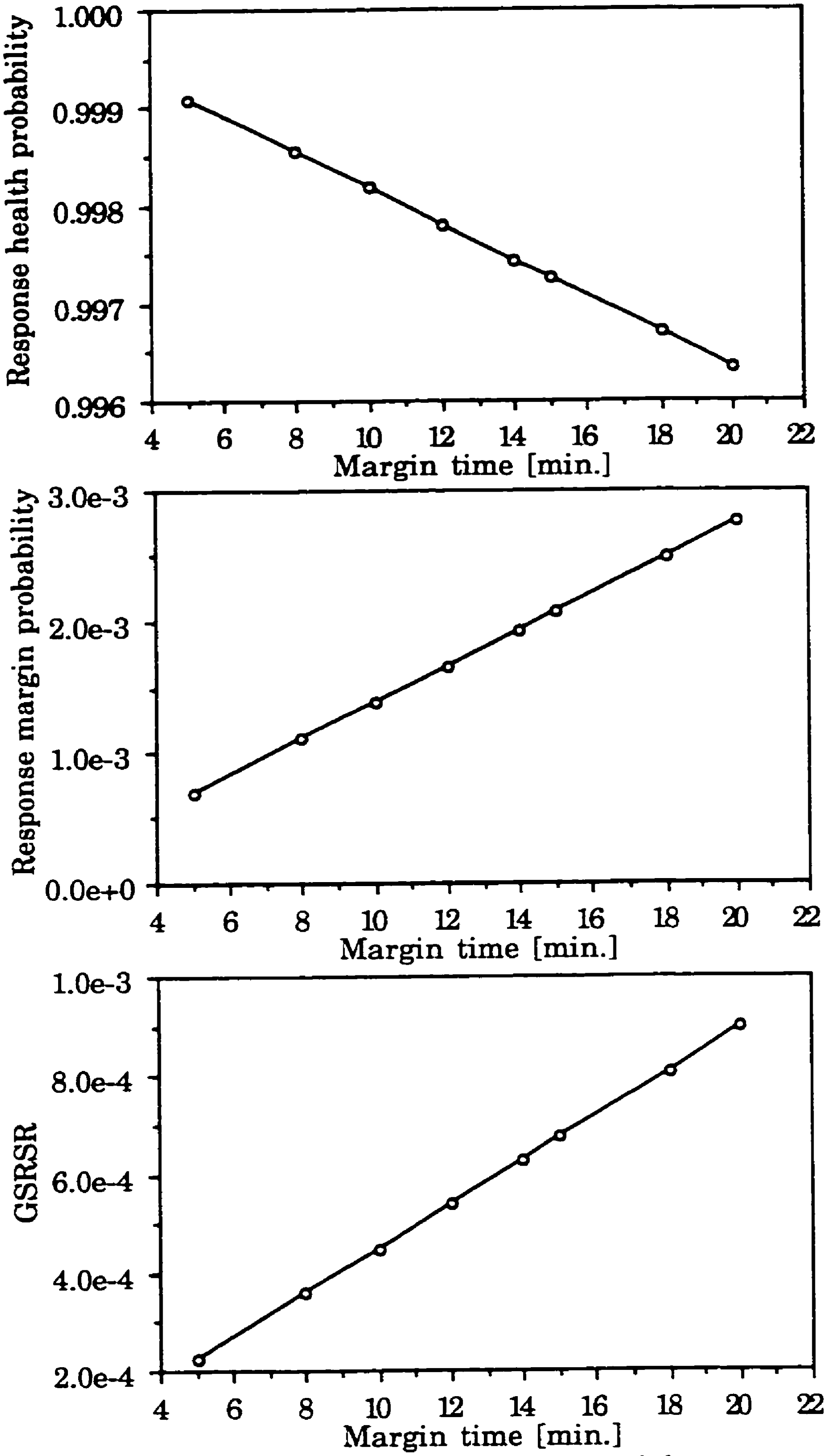

Figure 3.6: Response health, margin and risk probabilities versus margin time.

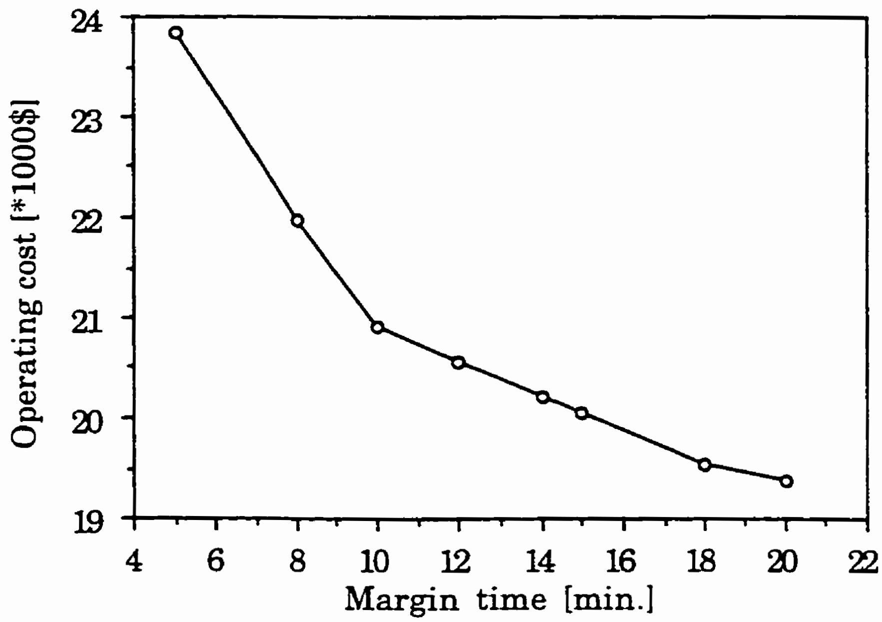

Figure 3.7: Operating cost versus margin time.

3.5.4 Effect of Load Forecast Uncertainty

Operating reserve assessment in a power system is normally based on an advance estimate of the hourly load variation within a short period of time. The prediction of future load is normally done on the basis of past data and weather forecasts. A certain degree of uncertainty exists between the forecast and the actual load due to the random nature of system loads, the non-linear relationship between the load and weather changes and inaccuracies in weather forecasting. Load forecast uncertainty can be reasonably approximated by a normal distribution [3]. The mean of the distribution is the forecast load. For computational simplicity, the normal distribution can be discretised into several class intervals. The probability associated with a class interval can be assigned to the load representing the class interval mid-point. In the studies presented in this paper a seven-step approximation of a normal distribution is used as shown in Figure 3.8.

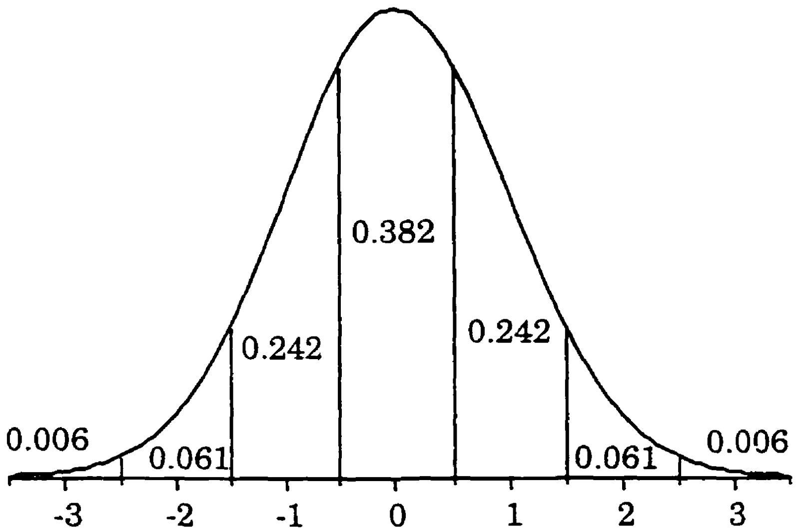

Figure 3.8: Seven step approximation of the normal distribution.

The effects of load forecast uncertainty on the unit commitment health, margin and risk probabilities are illustrated in [60]. The effects of load forecast uncertainty on the response health, margin and risk probabilities can be obtained using the following procedure. The number of committed units are determined, following which the economic load dispatch is done for each load step of the seven-step approximation. The response health, margin and risk probabilities are calculated for each load step. The economic reallocation of generating units to maintain an adequate response reserve while satisfying an acceptable response health and risk probabilities is done for each load step. For a given forecast load, the equivalent response health and risk must be acceptable. The equivalent response health, margin, risk probabilities and the expected operating cost are calculated using the following equations.

$$P_h(eq) = \sum_{i=1}^{s} P_h(i) \times P_l(i) \tag{3.16}$$

$$P_m(eq) = \sum_{i=1}^{s} P_m(i) \times P_l(i) \tag{3.17}$$

$$P_r(eq) = \sum_{i=1}^{s} P_r(i) \times P_l(i) \tag{3.18}$$

$$EX(C) = \sum_{i=1}^{s} C(i) \times P_l(i) \tag{3.19}$$

$$EX(U_j) = \sum_{i=1}^{s} U_j(i) \times P_l(i) \qquad j = 1, 2, \ldots, n \tag{3.20}$$

$$EX(RM) = \sum_{i=1}^{s} RM(i) \times P_l(i) \tag{3.21}$$

$$EX(LD) = \sum_{j=1}^{n} EX(U_j) \tag{3.22}$$

where,

$P_h(eq)$	Equivalent response healthy state probability,
$P_m(eq)$	Eequivalent marginal state probability,
$P_r(eq)$	Equivalent response risk probability,
$P_l(i)$	Probability of the *ith* load step in the normal distribution,
$EX(C)$	Expected operating cost in \$,
$EX(RM)$	Expected Regulating Margin in MW,
$EX(U_j)$	Expected output of the *jth* unit,
$EX(LD)$	Expected load demand,
s	Number of steps in the normal distribution,
n	Number of committed units,
$RM(i)$	Regulating margin of the *ith* step.

Table 3.11 shows the response indices for a forecast load of 1995 MW when load forecast uncertainty (LFU) is included. An additional unit to that shown in Table 2.3 must be committed to the system when the forecast load has a standard deviation of 4% of the forecast mean. The system with 14 committed units and at the load level of 1995 MW can satisfy a specified unit commitment risk of 0.001 and an acceptable healthy state probability of 0.9

[60]. The spinning reserve is allocated among the committed units using the above procedure such that a specified response risk of 0.001 and an acceptable response healthy state probability of 0.9 are satisfied. The Required Regulating Margin (RRM) is assumed to be 40% of the spinning reserve.

Table 3.11: System response indices for a load level of 1995 MW and a margin time of 10 minutes.

No. of SD	Load level	Prob. of load level	Cost [$]	Probability of response		
				Health	Margin	Risk
-3	1755	0.006	16905.86	0.99833226	0.00121889	0.00044885
-2	1835	0.061	17743.01	0.99833226	0.00121889	0.00044885
-1	1915	0.242	18595.14	0.99799653	0.00155462	0.00044885
0	1995	0.382	19519.88	0.99799653	0.00155462	0.00044885
1	2074	0.242	21146.79	0.99799653	0.00155485	0.00044862
2	2154	0.061	22807.01	0.99799653	0.00155485	0.00044862
3	2234	0.006	23746.27	0	0.99902585	0.00097415
Index including LFU			19791.60	0.99203104	0.00751702	0.00045193

SD = Standard Deviation

Table 3.12 shows the response indices for a seven step load model of the IEEE-RTS. The system, with the number of committed units and at the corresponding load level, can satisfy a specified unit commitment risk of 0.001 and an acceptable healthy state probability of 0.9 [60].In comparison with the results shown in Table 3.5 it can be seen that the required number of committed units increases at some load levels when including load forecast uncertainty. The response healthy state probability decreases at each load level, given that the number of committed units are the same [106]. The response risk, however, increases by including load forecast uncertainty.

Table 3.12: Response indices including load forecast uncertainty.

Load MW	No. of units	RRM MW	Cost $	Probability of response		
				Health	Margin	Risk
1140	9	241	10677.84	0.99886548	0.00057616	0.00055836
1425	10	206	14756.14	0.99269812	0.00681864	0.00048324
1710	12	216	16921.34	0.99235328	0.00716104	0.00048569
1995	14	226	19791.6	0.99203104	0.00751703	0.00045193
2280	17	232	25237.36	0.93080049	0.06858214	0.00061737
2565	21	240	29063.1	0.93043281	0.06890413	0.00066306
2850	32	202	33206.22	0.68783556	0.30546995	0.00669449

3.6 Conclusions

This chapter illustrates a technique developed to determine the optimum load dispatch for a set of committed generating units. The concepts of unit commitment health, margin and risk proposed in [60] are extended in this chapter to include the response capability of the committed units. A risk index designated as the GSRSR is defined as the load dispatch criterion. The dispatch should be such that specified system response criteria are satisfied. An algorithm is described in this chapter to determine the unit commitment and optimum dispatch of the committed units based on the specified commitment and response criteria. The results show that if a system has a high unit commitment healthy state probability it also has the potential to have a high response healthy state probability. This, however, depends upon the margin time, the response rate of the units and how the spinning reserve is allocated among the committed units.

The ability of a system to respond to sudden changes and pick up load depends on the type of units within the system. Interruptible load can also be considered as part of response reserve. The effects on the response health, margin and risk probabilities of factors such as stand-by units, interruptible load and postponable outages are illustrated and presented in the next chapter.

4. RESPONSE HEALTH CONSTRAINTS IN ECONOMIC LOAD DISPATCH CONSIDERING STAND-BY UNITS, INTERRUPTIBLE LOADS AND POSTPONABLE OUTAGES

4.1. Introduction

Adequate operating reserve is required in an electric power system in order to maintain a desired level of reliability through a given period of time [3]. The overall operating reserve can be generally categorized into two classes of unit reserve and system reserve. Generating unit operating reserve may be in the form of synchronized or non-synchronized units such as rapid start facilities. Synchronized and non-synchronized reserve are also referred to as spinning and stand-by reserve. Some utilities include in system reserve elements such as under frequency relaying, load shedding and interruptible load. System reserve is not as common among utilities as unit reserve.

As previously noted in Chapter 3, operating reserve assessment involves studies of both the unit commitment and dispatch of the committed units. These two aspects are conceptually different and deal with different reliability issues. A basic framework for unit commitment was proposed in [60] which focuses on the degree of system well-being, in the form of unit commitment health and margin, in addition to the more conventional analysis of risk. This technique was extended in [61] to incorporate stand-by equipment, interruptible load and postponable outages. On the basis of this technique, a system with high healthy state probability has sufficient spinning reserve to tolerate any single unit outage.

The basic concepts of response health, margin and risk are presented in Chapter 3 in which it was assumed that the response is provided only by the spinning units. Reliable power system operation requires that the system generation has high healthy state probabilities for both unit commitment and response requirements. The load dispatch should be such that the system should have sufficient response within a certain margin time to withstand system disturbances. The ability of a system to respond to sudden changes and pick up load depends on its unit types [107]. Thermal units can pick up 1-3% of their full output capacity in one minute. Hydro units can normally pick up load up to 30% of their full output capacity in approximately one minute. Rapid start gas turbine units can also pick up load in a very short period of time and the lead time associated with starting, synchronizing and loading these units could be in the order of five minutes. Rapid start units, therefore, can participate in the response health, margin and risk constrained load dispatch if their lead time is less than the specified margin time. A procedure is illustrated in this chapter to determine how far the acceptable load dispatch must be from the economic load dispatch in order to satisfy the response requirement. The effects on the response health, margin and risk probabilities of factors such as stand-by units, interruptible load, postponable outages and margin time are illustrated and presented in this chapter.

4.2 Overall Philosophy of Operating Health, Margin and Risk

As previously noted, operating health analysis involves the two different phases of unit commitment and response health analysis. The concept of unit commitment health, margin and risk are illustrated in Chapter 2 where the system performance is identified as being in either the comfort or at risk domains. The comfort domain consists of the healthy and marginal zones. In the healthy zone, a system has sufficient spinning reserve and is well removed from the risk zone and is relatively safe. A system with inadequate spinning reserve is in the marginal zone, in which the outage of a specific single unit will result in load curtailment or entrance into the risk zone.

A complete picture of operating health (H), margin (M) and risk (R) is shown in Figure 4.1 where the comfort zone is divided into areas H1H2, H1M2, M1M2 and M1H2 in which unit commitment and response are designated by 1 and 2 respectively. The risk zone consists of the three areas H1R2, M1R2 and R1R2. Two different cases are examined in order to make Figure 4.1 more understandable.

Response	Unit Commitment: Health (H1)	Margin (M1)	Risk (R1)
H2	H1H2	M1H2	Does not exist
M2	H1M2	M1M2	Does not exist
R2	H1R2	M1R2	R1R2

Figure 4.1: Complete picture of operating health analysis

4.2.1 Reserve in the System is Only Spinning Reserve

Spinning reserve is the rotating capacity in excess of the system load which is synchronized and immediately available to take up load [3]. In area H1H2, the system not only has sufficient spinning reserve but is also capable of responding to the loss of any single dispatched unit within a certain margin time. This is the safest area and the system operating objective is to operate the system with a high probability of being in this area. The system does not have adequate response capability in area H1M2 even though the amount of spinning reserve is identical to that of the H1H2 area. Having a high probability of being in this area is a warning to the system operator to make the necessary changes to the unit loadings and to transfer the system to the H1H2 area. In area M1M2, the spinning reserve is insufficient to produce a suitable response. The system can never come to the M1H2 area if the reserve in the system is only spinning reserve.

4.2.2 Including Stand-by Units and Interruptible Loads

Unit commitment health, margin and risk analysis including stand-by units and interruptible loads are considered in [61]. Reference 61 notes that stand-by units and interruptible loads cannot transfer the system to the healthy state if it is initially in the marginal state. These units, however, can increase the response capability of the generating system and move the system to the response healthy state from the marginal state provided that their lead time is less than the margin time. The system can transfer from H1M2 and M1M2 to H1H2 and M1H2 respectively by including rapid start units and interruptible loads. The area M1H2 can exist if stand-by units and interruptible loads are part of the operating reserve.

4.3 Modeling of Stand-by Units

4.3.1 Rapid-start Unit Model

One of the most important requirements in a meaningful quantitative reliability evaluation is correct modeling of the basic system components [108-110]. In the basic two-state model presented in Section 3.4, it is assumed that once a unit is called for service, the probability of failing to come into operation is zero. This is not generally true in the case of rapid start units and therefore the possibility of their failure to start must be included. A convenient and practical model [19,111] for a rapid start unit is shown in Figure 4.2. The various transition rates can be obtained from the number of transitions between the states divided by the residence times in the various states [112].

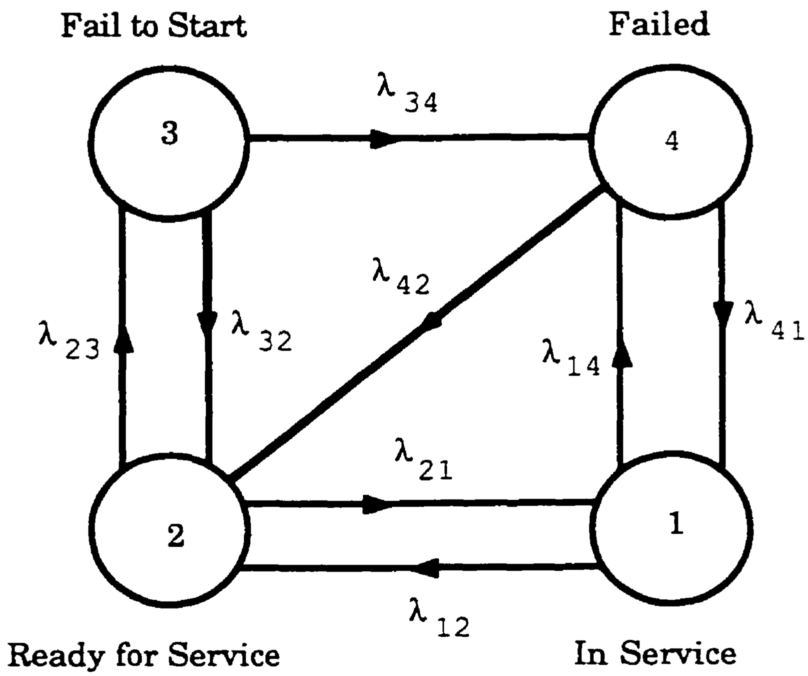

Figure 4.2: Four-state model for rapid start units.

The time dependent state probabilities can be evaluated using a matrix multiplication [1] technique. This is a very powerful method for obtaining time dependent probabilities of complex systems and is illustrated using the model of Figure 4.2.

$$[P(t)] = [P(0)][P]^n \tag{4.1}$$

Where,

$[P(t)]$	Vector of state probabilities at time t,
$[P(0)]$	Vector of initial probabilities,
$[P]$	Stochastic transitional probability matrix,
n	Number of time steps used in the discretisation process.

The stochastic transitional probability matrix for the model shown in Figure 4.2 is as follows:

$$[P] = \begin{bmatrix} 1-(\lambda_{12}+\lambda_{14})\Delta t & \lambda_{12}\Delta t & 0 & \lambda_{14}\Delta t \\ \lambda_{21}\Delta t & 1-(\lambda_{21}+\lambda_{23})\Delta t & \lambda_{23}\Delta t & 0 \\ 0 & \lambda_{32}\Delta t & 1-(\lambda_{32}+\lambda_{34})\Delta t & \lambda_{34}\Delta t \\ \lambda_{41}\Delta t & \lambda_{42}\Delta t & 0 & 1-(\lambda_{41}+\lambda_{42})\Delta t \end{bmatrix} \tag{4.2}$$

The number of matrix multiplications, i.e. n, is equal to the time of interest t divided by the time interval Δt. During the start-up time, a unit is not able to take up load and resides in the ready-for-service state with a probability of unity. However, at the time when the unit may contribute to the system generation, the unit can be in either state 1 or state 4. Therefore, the vector of initial probabilities is:

$$[P(0)] = [P_1(0) \quad 0 \quad 0 \quad P_4(0)]. \tag{4.3}$$

where,

$$P_4(0) = \frac{\textit{total number of times unit failed to take up load}}{\textit{total number of starts}} \tag{4.4}$$

$$P_4(0) = \frac{\lambda_{23}}{\lambda_{23} + \lambda_{21}} \tag{4.5}$$

$$P_1(0) = 1 - P_4(0) \tag{4.6}$$

The probability of finding the unit on outage given that a demand has occurred is given by [3] :

$$P(\mathit{Down}) = \frac{P_3(t) + P_4(t)}{P_1(t) + P_3(t) + P_4(t)} \tag{4.7}$$

$$P(\mathit{Up}) = 1 - P(\mathit{Down}) \tag{4.8}$$

4.3.2. Hot Reserve Unit Model

When a thermal unit is removed from service it can be left in one of two states; hot reserve and cold reserve. In a cold reserve state, both the unit and its boiler are completely shut down [3]. In a hot reserve state, however, the boiler is maintained in a banked state. A hot reserve unit can be represented by the five-state model shown in Figure 4.3. The time dependent state probabilities can be calculated using the same technique described for a rapid start unit. The vector of initial probabilities is [3]:

$$[P(0)] = [P_1(0) \quad 0 \quad 0 \quad P_4(0) \quad 0]. \tag{4.9}$$

where $P_4(0)$ and $P_1(0)$ are calculated using Equations 4.5 and 4.6 respectively. The probability of finding the unit on outage given that a demand has occurred is given by [3]:

$$P(\mathit{Down}) = \frac{P_3(t) + P_4(t) + P_5(t)}{P_1(t) + P_3(t) + P_4(t) + P_5(t)}. \tag{4.10}$$

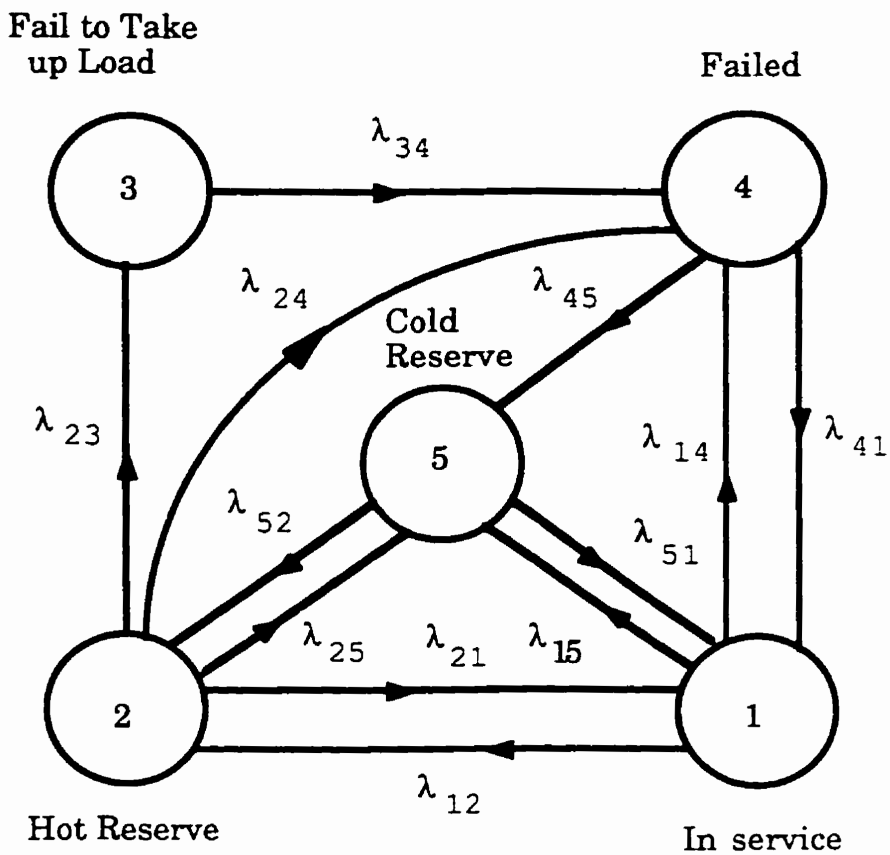

Figure 4.3: Five-state model for hot reserve units.

$$P(Up) = 1 - P(Down). \tag{4.11}$$

The corresponding transition rates of the rapid start and hot reserve units are given in Appendix D.

4.4 Model for Postponable Outages

When a unit is removed from service due to equipment failure, it can be either removed immediately or the removal postponed for a certain limited period of time. The conventional definition of a forced outage includes both sudden and deferrable or non-sudden unit removal from service [113]. The concept of both sudden and deferred unit removal from service does not pose any difficulty in a planning study but causes some problems in operating reserve evaluation. In practice, many of the failures that occur can be tolerated for a short period of time and the removal of the unit for repair can be postponed [3]. In these cases, the unit may still be capable of production if it is considered necessary to the system. This is obviously not true for all unit failures as some failures require immediate unit removal. The two-state model has been modified in [113] to include postponable outages as shown in Figure 4.4.

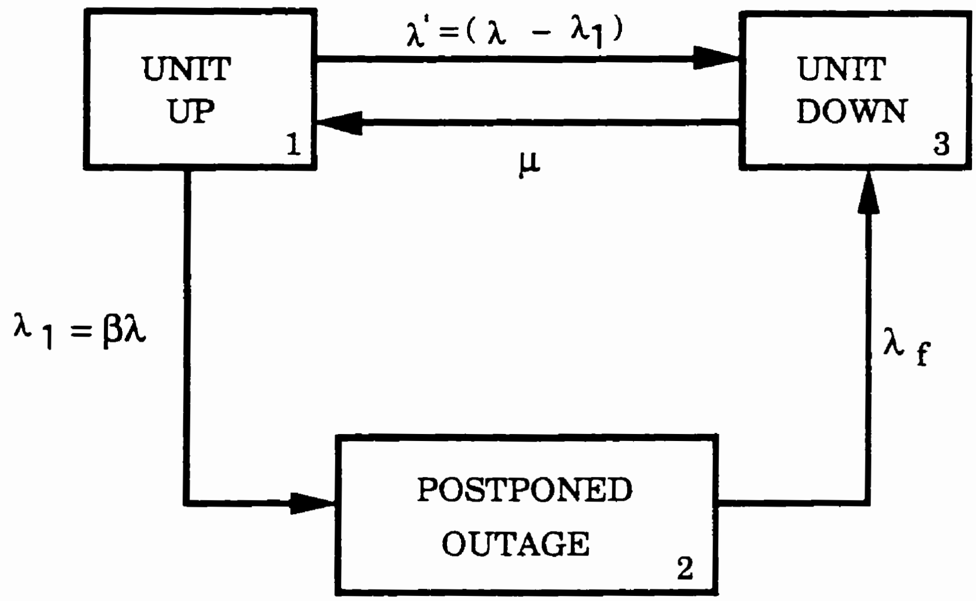

Figure 4.4: Postponable outage model.

Where,

λ_1	Rate of outages that can be postponed,
λ'	Rate of outages that can not be postponed,
λ	Total failure rate $=\lambda'+\lambda_1$,
λ_f	Rate at which postponed outages are forced into the 'Failed and removed from service' state,
β	Proportion of λ that can be postponed $=\frac{\lambda_1}{\lambda}$

The probability of the unit being in the down state considering postponable outages can be calculated using Equation 4.12 [113,114].

$$P(down) \cong \lambda' MT = (1-\beta)\lambda MT = \text{Modified O.R.R.} \tag{4.12}$$

Since β is between zero and 1, the modified O.R.R is always less than the original O.R.R. β=0 corresponds to the conventional two-state unit model and β=1 represents to the case where all forced outages can be postponed [113].

4.5 Evaluation Technique

Once the number of committed units are determined with a specified unit commitment criterion, the next step is to determine the power outputs of the committed generators such that the operating cost is minimized. The actual operating ranges of all the committed units are restricted by their ramp rate characteristics. This represents additional constraints in the dispatch problem. Starting from an economic schedule, not only must the reserve be sufficient to make up for a generating unit failure, but the reserve must be allocated among the fast-responding and slow-responding units.

Given the available response output, the associated system response health, margin and risk probabilities for the designated load dispatch can be determined. This is done using the contingency enumeration technique. For a given contingency, the committed units are arranged in two sets. In set 1, m_1 units are in service and in set 2, m_2 units are on outage. The probability associated with the contingency is calculated using Equation 4.13.

$$P_c = \prod_{i=1}^{m1}(1-\lambda_i \times MT)\prod_{j=1}^{m2}(\lambda_j \times MT) \tag{4.13}$$

$$m_1 + m_2 = n \tag{4.14}$$

Each contingency must be evaluated to determine which response state it belongs to based on the state definitions given in Section 3.3. This is determined using the following equations;

$$\sum_{i=1}^{m1} L_i + ARES_c > (RRM + LOAD), \tag{4.15}$$

$$ARES_c - RESO_k > L_k \qquad (k = 1, 2, \ldots, m_1). \tag{4.16}$$

Where,

n	Number of spinning units,
P_c	Probability of occurring the contingency c,
λ_i	Failure rate of i_{th} unit in $fr\,/\,min.$,
MT	Margin time in minute,
$RESO_k$	Response output of the k_{th} unit in MW,
L_k	Loading of the i_{th} unit in MW,
RRM	Required regulating margin in MW,
$ARES_c$	Total available response at contingency c in MW.

If both Equations 4.15 and 4.16 are satisfied, the contingency lies in the healthy state. If only Equation 4.15 is satisfied, it belongs to the marginal state. If Equation 4 is not satisfied, the system is in the state of risk. By varying m_2 from 0 to n, all possible contingencies can be considered.

The total available response is provided by the on-line spinning units, stand-by units, interruptible load, etc.. Stand-by equipment can increase the amount of response magnitude, provided that their lead times are less than the margin time. The lead time associated with hot reserve units is such that these units do not contribute to the response output of the generation system. Rapid start units, however, can respond extremely quickly and hence significantly decrease the response risk and increase the response magnitude.

The response characteristics of typical rapid start units are illustrated in Figure 4.5 and evaluated in Equation 4.17.

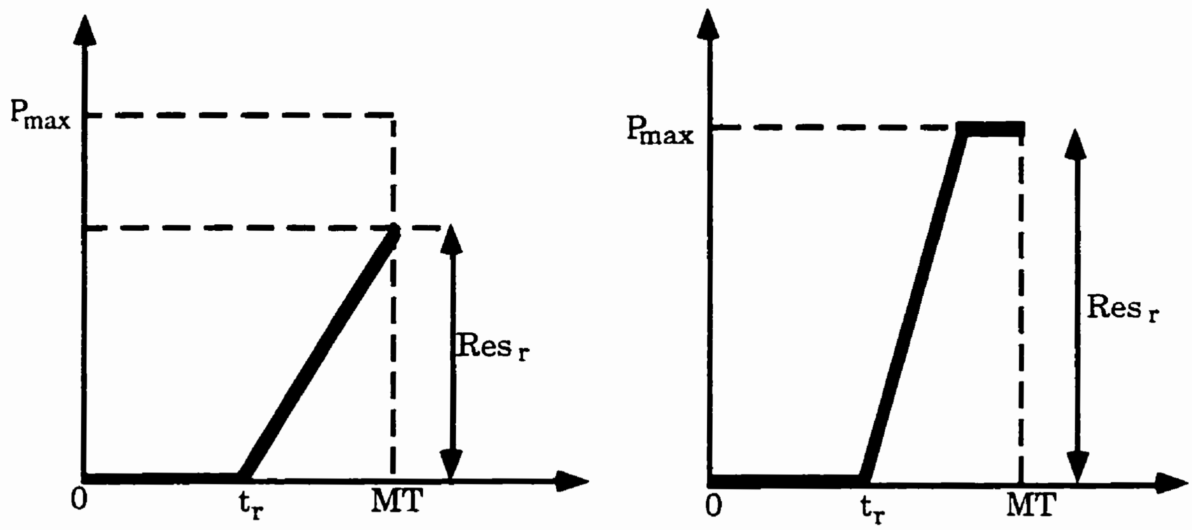

Figure 4.5: Response characteristic of typical rapid start units.

$$Res_r = 0 \qquad \text{If} \quad t_r \geq MT. \tag{4.17a}$$

$$Res_r = Min[(MT - t_r) \times RR_r, P_{max}] \qquad \text{If} \quad t_r < MT. \tag{4.17b}$$

where,

Res_r	Rapid start unit response output,
RR_r	Rapid start unit response rate,
P_{max}	Maximum capacity of the rapid start unit,
t_r	Lead time of rapid start units.

The response health, margin and risk probabilities including rapid start units are obtained using the conditional probability approach [1]. The probability of a rapid start unit being available at the margin time is calculated using the matrix multiplication technique [1] and the probability $P(A_k)$ that event (A_k) occurs, is determined using the binomial distribution [1].

$$P_h^r = \sum_{k=0}^{NR} [P_h^{r,k}|A_k] \times P(A_k) \tag{4.18}$$

$$P_m^r = \sum_{k=0}^{NR} [P_m^{r,k}|A_k] \times P(A_k) \tag{4.19}$$

$$GSRSR = \sum_{k=0}^{NR} [GSRSR^k|A_k] \times P(A_k) \tag{4.20}$$

$$EXRES = \sum_{k=0}^{NR} [Res_r|A_k] \times P(A_k) \tag{4.21}$$

where,

P_h^r, P_m^r and $GSRSR$	Response health, margin and risk indices,
NR	Total number of rapid start units,
(A_k)	k out of NR rapid start units are in service at the margin time,
$EXRES$	Expected response from rapid start units,
$[P_h^{r,k}\|A_k]$	Response healthy state probability given that k rapid start units are available at the margin time in addition to the on-line spinning units,
$[P_m^{r,k}\|A_k]$	Response marginal state probability given that k rapid start units are available at the margin time in addition to the on-line spinning units,
$[GSRSR^k\|A_k]$	Response risk given that k rapid start units are available at the margin time in addition to the on-line spinning units.

In addition to the generating capacity adjustments, some utilities have loads which can be curtailed within a short period of time. The magnitude of the curtailable load and the corresponding time of interruption depend on the agreements between the utility and its consumers. The costs associated with the interruptions vary for different loads. Interruptible load can increase the available response in the system provided that the time of load interruption is less than the margin time. Interruptible load can be considered for computational purposes as an equivalent rapid start unit having a lead time of TI, a capacity of LI and with a failure rate equal to zero. The response indices can therefore be calculated using Equations 4.18 to 4.21, in which the probability of having LI MW of load interrupted at the lead time of TI, if required, is considered to be unity. The overall system response characteristic is shown in Figure 4.6, in which the total response in the system is provided by on-line spinning units, rapid start units and interruptible load.

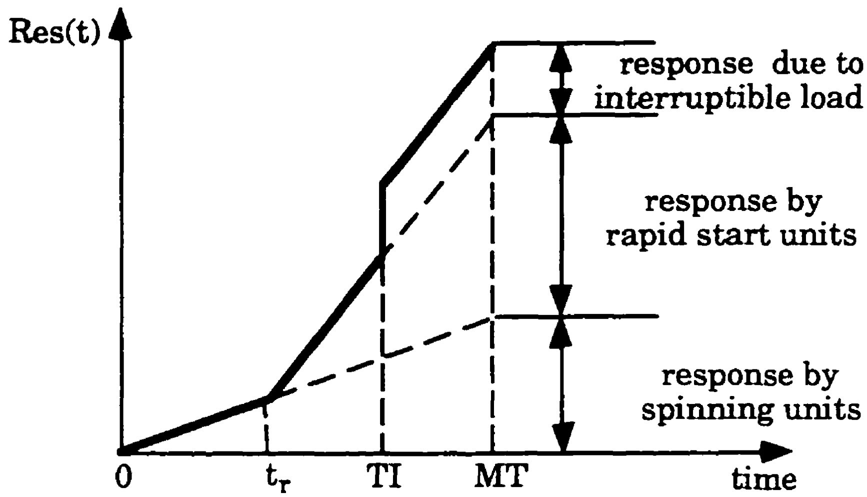

Figure 4.6: Overall system response characteristic.

Once the system response state probabilities are calculated, the response indices are compared with the specified values. When the response criteria are not satisfied, the load dispatch must be adjusted. For reloading, the dispatched units are classified into three groups in which their spinning reserve (SP) is equal to, less than, or greater than their response capability (RC). The response characteristic associated with each group is shown in Figures 4.7, 4.8 and 4.9. In the next step, an incremental load is taken away from the unit in Group II whose incremental running cost at the respective load point is the highest, and given to the unit in Group III whose incremental running cost is the lowest. This procedure should be continued to provide sufficient responsive reserve to satisfy a specified response risk, a specified response health probability or both. Adjustments to the unit loading

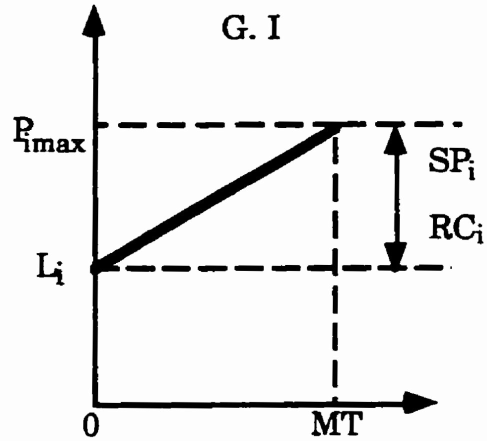

Figure 4.7: Response characteristic of an on-line spinning unit $(SP = RC)$.

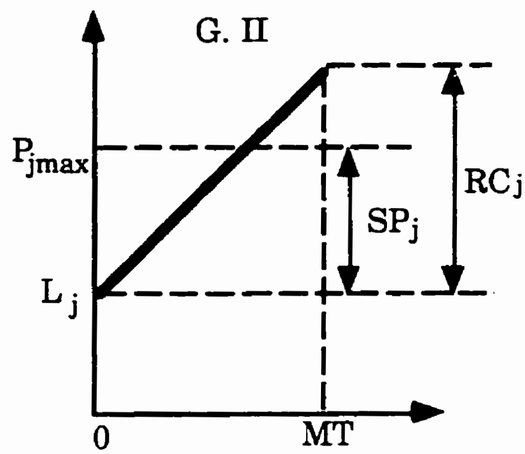

Figure 4.8: Response characteristic of an on-line spinning unit $(SP < RC)$.

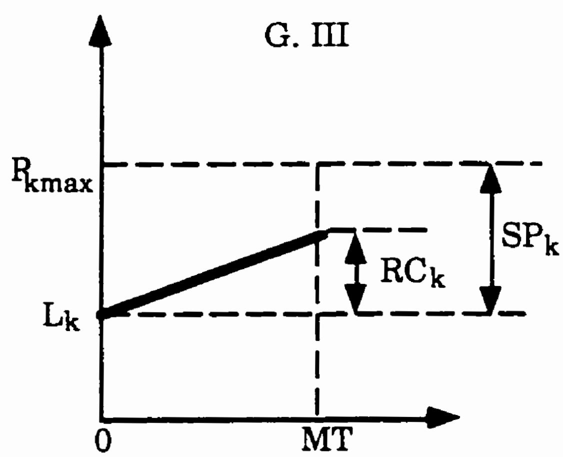

Figure 4.9: Response characteristic of an on-line spinning unit $(SP > RC)$.

cannot be continued if all the units are in Group I or if there is no unit in Groups II or III. In this case, if the response criterion is not satisfied then more unit(s) must be committed in addition to those already in service.

4.6 Application to the IEEE Reliability Test System

The IEEE-RTS has been used to demonstrate the application of the proposed method. In the studies presented in this section, the abbreviations ELD, LDS and LDM are used to designate the studies with an economic load dispatch, load dispatch with a single response criterion and load dispatch with multiple response criteria. For the single response criterion, the load dispatch is based upon a specified GSRSR of 0.001. The additional response healthy state probability of 0.9 is used for load dispatch with multiple response criteria.

4.6.1 Unit Commitment Including Stand-by Units and Interruptible Load

The IEEE-RTS has a number of 25 MW gas turbines [115] and several 100 MW hot reserve units. The lead time associated with rapid start and hot reserve units are assumed to be 5 minutes and one hour respectively. The rapid start and hot reserve units are represented by the four state and five state models shown in Figures 4.2 and 4.3 respectively . The corresponding transition rates are given in Appendix D. In addition to stand-by units, some utilities consider interruptible load as a part of the operating reserve [51]. Table 4.1 shows the unit commitment health, margin and risk probabilities for a load level of 1710 MW and 11 units when the system lead time is 4 hours. Case 1 is the unit commitment assuming that the reserve in the system is only spinning reserve. In Case 2, the system has two rapid start and one hot reserve unit in addition to the 11 on-line committed units. In Case 3, it is assumed that 50 MW of the system load can be curtailed within 5 minutes. The system has a zero healthy state probability at the load level of 1710 MW in Case 1 and does not improve considerably by including stand-by units or interruptible load [61,116].

Table 4.1: Unit commitment in the IEEE-RTS.

Case	Load MW	No. of units	SP MW	Unit commitment		
				Health	Margin	Risk
1	1710	11	386	0	0.9926059	0.0073941
2	1710	11	386	0.0000514	0.9995008	0.0004478
3	1710	11	386	0.0000520	0.9995796	0.0003684

In order to demonstrate the effects of stand-by units and interruptible loads on the response well-being, the three cases are individually illustrated as follows. For the studies presented in this section, it is assumed that the required regulating margin is 40% of the spinning reserve (SP) and the margin time is 10 minutes.

4.6.2 Response Indices Without Stand-by Units (Case 1)

Response constrained economic load dispatch considering only spinning reserve was illustrated in detail in Chapter 3. Table 4.2 shows the economic load dispatch (ELD) and load dispatch with single (LDS) and multiple response criteria (LDM) for a load level of 1710 MW with 11 units. The response indices associated with each load dispatch are shown in Table 4.3.

Table 4.2: Load dispatch for a load level of 1710 MW and 11 units.

LD	Load	Cost [$]	U1	U2	U3	U4	U5	U6	U7	U8	U9	U10	U11
ELD	1710	16056.39	50	50	50	50	400	400	315	80	80	80	155
LDS	1710	16955.76	50	50	50	50	400	400	260	112	112	111	115
LDM	1710	18393.80	0	34	50	50	400	400	260	137	137	137	105

Table 4.3: Response indices for the load dispatches of Table 4.2.

LD	Load MW	RRM MW	SP MW	Probability of response			Response MW
				Health	Margin	Risk	
ELD	1710	154	386	0	0.9988527	0.0011473	215
LDS	1710	154	386	0	0.9990262	0.0009738	310
LDM	1710	154	386	0	0.9995518	0.0004482	386

It can be seen from Table 4.3 that the economic load dispatch cannot satisfy a specified GSRSR of 0.001 because of insufficient response capacity. More response is available by adjusting the unit loadings and the single response criterion can be satisfied. The system is in the marginal state (M1) at a load level of 1710 MW and 11 units based on unit commitment and therefore cannot satisfy a specified response health probability of 0.9 even though all the spinning reserve, i.e. 386 MW, is available within the margin time. In other words, the system cannot come to the M1H2 area because of insufficient response capability. In this case, one more unit must be committed. With 12 units the unit commitment health, margin and risk probabilities change to 0.9687194, 0.0310479 and 0.0002327 respectively. Tables 4.4 and 4.5 show the load dispatches and the associated response indices for the load level of 1710 MW and 12 units.

Table 4.4: Load dispatch for a load level of 1710 MW and 12 units.

LD	Cost [$]	U1	U2	U3	U4	U5	U6	U7	U8	U9	U10	U11	U12
ELD	16142.42	50	50	50	50	400	400	240	80	80	80	115	115
LDS	16142.75	50	50	50	50	400	400	247	80	80	80	111	112
LDM	16766.30	19	50	50	50	400	400	260	91	90	90	105	105

Table 4.5: Response indices for the load dispatches of Table 4.4.

LD	Load MW	RRM MW	SP MW	Probability of response			Response MW
				Health	Margin	Risk	
ELD	1710	216	541	0	0.9986792	0.0013208	350
LDS	1710	216	541	0	0.9992047	0.0007953	357
LDM	1710	216	541	0.9983433	0.0012083	0.0004484	401

4.6.3 Response Indices With Stand-by Units (Case 2)

The lead time and the response rate of the rapid start units are assumed to be 5 minutes and 5 MW/min. respectively. The expected response from the two 25 MW units is 40.17 MW, based on Equation 10. Table 4.6 shows the results including two rapid start units. The response indices are presented in Table 4.7. Compared to the results shown in Table 4.3, the system can satisfy multiple response criteria by including rapid start gas turbine units. The response healthy state probability at a load level of 1710 MW and 11 spinning units increases from zero (Table 4.3, LDM) with no rapid start unit to

Table 4.6: Load dispatch considering stand-by units.

LD	Load	Cost [$]	U1	U2	U3	U4	U5	U6	U7	U8	U9	U10	U11
ELD	1710	16056.39	50	50	50	50	400	400	315	80	80	80	155
LDS	1710	16474.31	50	50	50	50	400	400	284	95	95	95	141
LDM	1710	18190.46	0	44	50	50	400	400	260	134	134	133	105

Table 4.7: Response indices for the load dispatches of Table 4.6.

LD	Load MW	RRM MW	SP MW	Probability of response Health	Margin	Risk	Response MW
ELD	1710	154	386	0	0.9988527	0.0011473	255.17
LDS	1710	154	386	0	0.9993039	0.0006961	300.17
LDM	1710	154	386	0.9599109	0.0396411	0.0004480	416.17

0.80217881 and 0.9599109 (Table 4.7, LDM) with one and two rapid start units respectively. The system operating zone now changes from M1M2 to M1H2.

The operating cost also varies with the situation. For load dispatch with multiple response criteria, the system operating cost is \$16766.30 (Table 4.4, LDM) for 12 spinning units with no stand-by units and increases to \$18190.46 (Table 4.6, LDM) for 11 spinning units and two rapid start units. Both operating conditions satisfy multiple response criteria but the latter is more expensive. Figure 4.10 shows the variation in the operating cost versus the number of rapid start units for load dispatch with a single response criterion. The system operating cost can be decreased to a minimum value or the cost associated with the most economic load dispatch. At this point, the cost remains constant as the number of rapid start units increase. The operating cost at a load level of 1995 MW and 13 units is \$20133.88 with no stand-by units and decreases to \$19381.05, which is the cost associated with economic load dispatch with 4 rapid start units. Figure 4.11 shows the number of spinning units and the required number of rapid start units such that the economic load dispatch can satisfy both single and multiple response criteria.

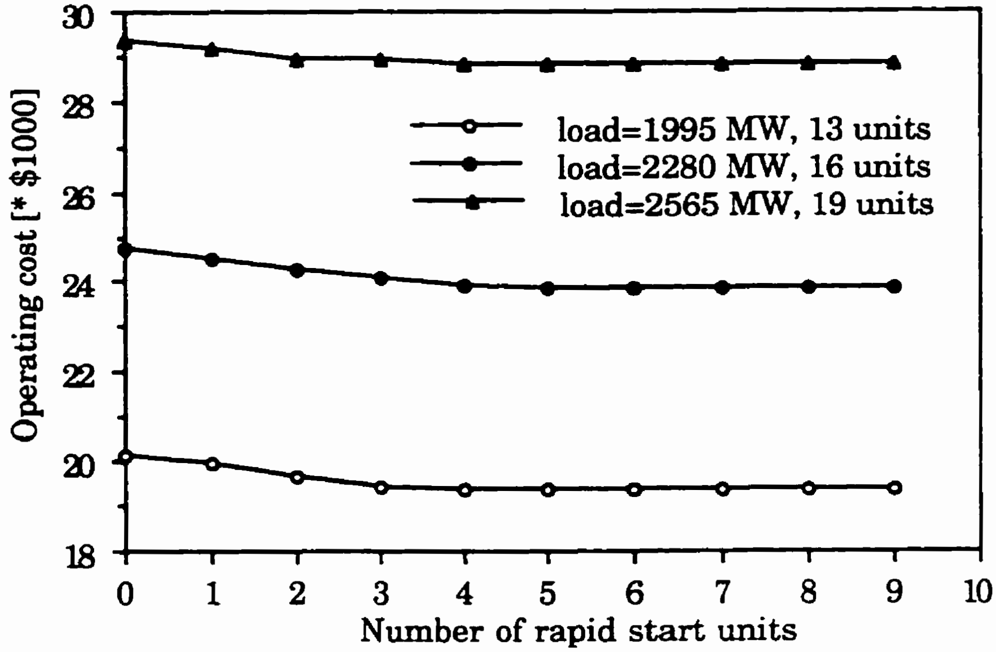

Figure 4.10: Variation in the operating cost versus number of rapid start units.

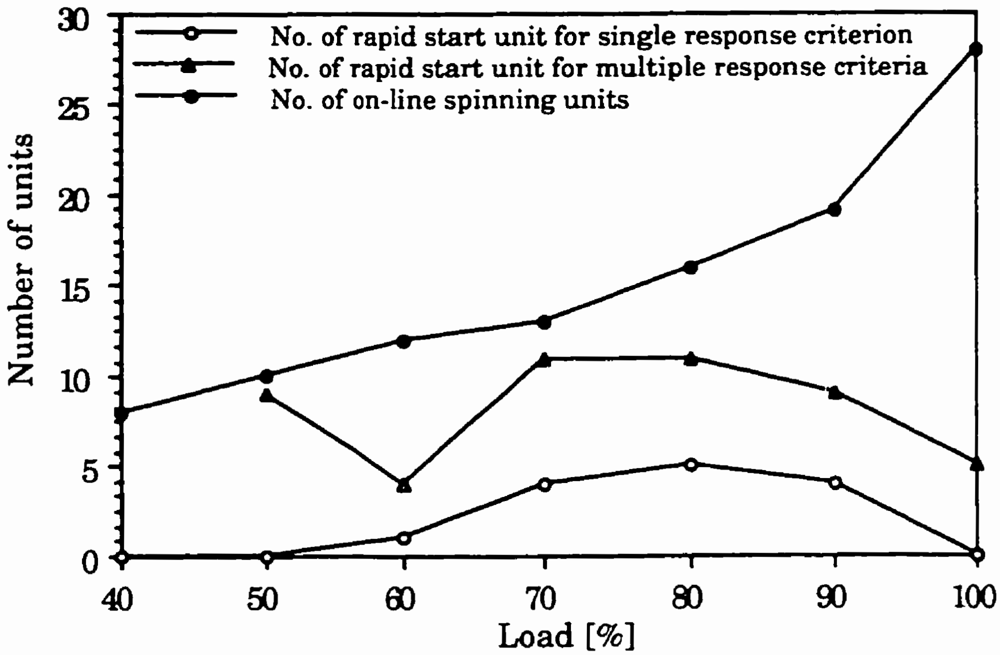

Figure 4.11: Required number of spinning and rapid start units for different load levels.

4.6.4 Response Indices Including Interruptible Load (Case 3)

Table 4.8 shows the economic load dispatch and load dispatch with single and multiple response criteria for a load level of 1710 MW and 11 spinning units when 50 MW of load is considered as interruptible load. The associated response indices are shown in Table 4.9. Compared to the results shown in Tables 4.2 and 4.3, the system can transfer to the healthy state from the marginal state when interruptible load is included in the analysis. For a single response criterion, operating cost decreases from $16955.76 when the system has only spinning reserve, to $16464.87 when interruptible load is considered.

Table 4.8: Load dispatch considering interruptible load.

LD	Load	Cost [$]	U1	U2	U3	U4	U5	U6	U7	U8	U9	U10	U11
ELD	1710	16056.39	50	50	50	50	400	400	315	80	80	80	155
LDS	1710	16464.87	50	50	50	50	400	400	285	95	95	94	141
LDM	1710	17682.96	0	44	50	50	400	400	260	126	125	125	105

Table 4.9: Response indices for the load dispatches of Table 4.8.

LD	Load MW	RRM MW	SP MW	Probability of response			Response MW
				Health	Margin	Risk	
ELD	1710	154	386	0	0.9988527	0.0011473	265
LDS	1710	154	386	0	0.9990279	0.0009721	309
LDM	1710	154	386	0.9985168	0.0010352	0.0004480	401

4.6.5 Discussion

From these studies, it can be concluded that for reliable and economic operation, unit commitment including stand-by units and interruptible loads should be done such that the system has a high healthy state probability [60,61]. Load dispatch should then be done to provide a high response healthy state probability at minimum cost. Using this approach, the response is mostly provided by rapid start units and interruptible load, if available, and the system operates economically in the area H1H2 [117].

4.6.6 Effect of Postponable Outages

In a practical power system, many failure events can be tolerated and the outage of a failed unit can be postponed for a limited period of time without creating additional damage. The degree to which the outage of a failed unit can be postponed depends on the time period considered. The time consideration in a unit commitment study is the lead time and that of response analysis is the margin time, which is considerably less than the lead time. The possible influence of postponability is, therefore, higher for the second aspect than for the first. The effects of the degree of unit postponability on the unit commitment health, margin and risk probabilities were examined in [61] where it was assumed that the 350 MW and 197 MW units of the IEEE-RTS can have some outages postponed with different values of β .

Figure 4.12 shows the variation in the GSRSR for the economic load dispatch of 13 and 12 units at load levels of 1995 MW and 1710 MW respectively. It can be seen that the GSRSR decreases as the degree of postponability β, increases. A specified GSRSR of 0.001 can be satisfied at β equal to 0.75 and 0.48 for load levels of 1995 and 1710 MW respectively. The system operating cost, therefore, decreases for the same response criterion by including outage postponability.

Consider the unit commitment and the load dispatch of the IEEE-RTS such that both unit commitment and response health probabilities are greater than 0.9. Figure 4.13 shows the variation in the response health

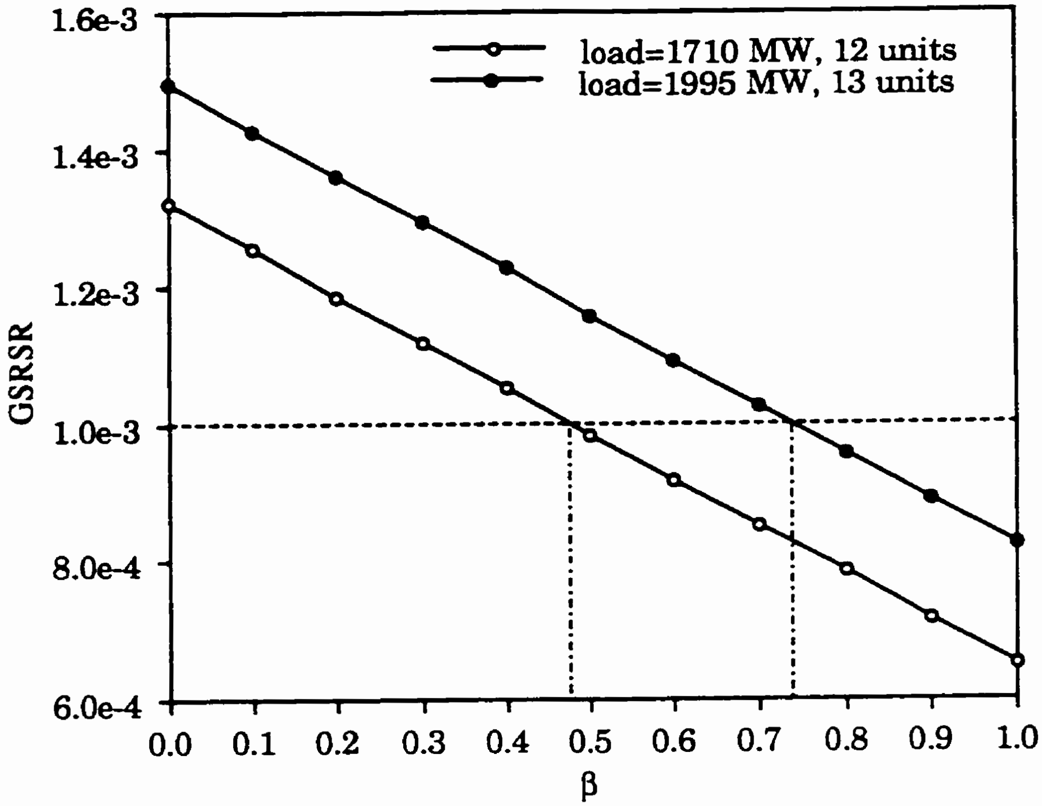

Figure 4.12: Variation in GSRSR versus β.

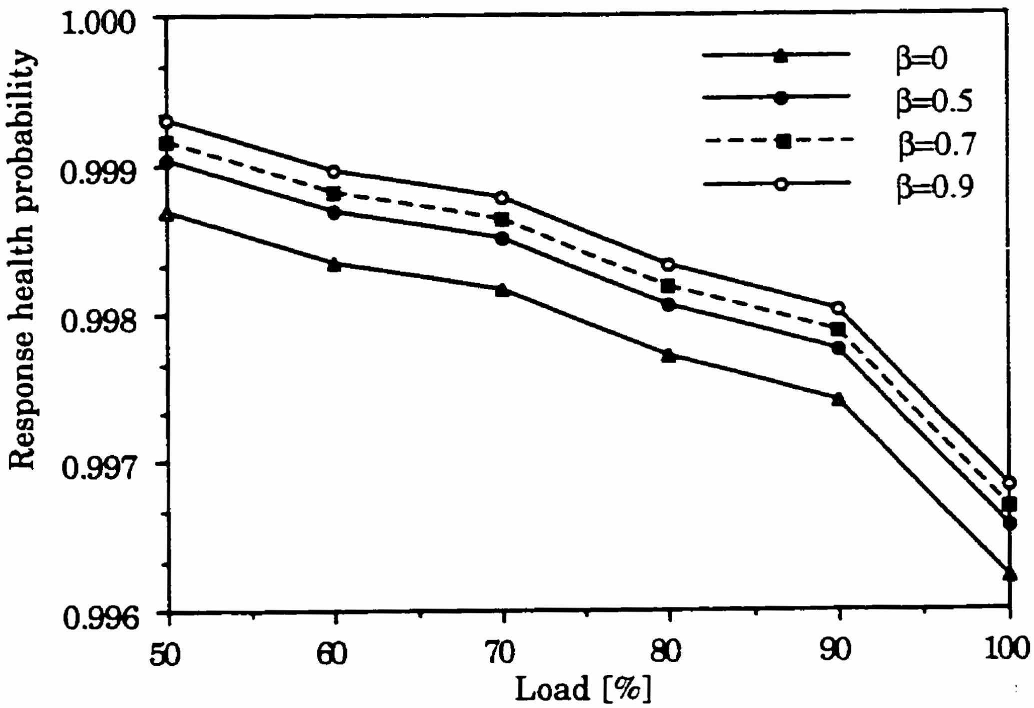

Figure 4.13: Variation in response health probability for different load levels.

probability for different values of β. It can be seen from Figure 4.13 that for a given load level the response health probability increases as β increases.

4.7 Conclusions

The concept of unit commitment health, margin and risk described in Chapter 2 is extended in this chapter to evaluate the response well-being of a generating system. The superposition of the unit commitment and response health, margin and risk are pictorially illustrated in this chapter in order to make these concepts more understandable. A procedure is presented to determine the load dispatch required to satisfy the response criterion. The study results presented illustrate the effects of variation in the margin time on the response health, margin and risk probabilities by application to the IEEE-RTS.

The effects of including rapid start units, interruptible loads and postponable outages on the response well-being are also illustrated. An important impact of rapid start units and interruptible loads is that a system which is in the marginal response state because of insufficient responsive reserve can transfer to the healthy state when they are included. This cannot happen in a unit commitment assessment [61]. The results also show that for a given load dispatch, the response risk decreases when the degree of postponability increases. The degree to which the outage of a failed unit can be postponed is more important in response analysis than in unit commitment assessment.

System well-being can be considerably improved by interconnection with another system. Each system can operate at either the same or at a higher operating state level with a lower reserve than would be required without interconnection. The concepts of unit commitment health analysis are extended in Chapter 5 to evaluate the spinning reserve requirements in interconnected systems.

5. UNIT COMMITMENT HEALTH ANALYSIS FOR INTERCONNECTED SYSTEMS

5.1 Introduction

Most electric power utilities operate as members of an interconnected system. Interconnection to one or more other systems provides a definite improvement in system adequacy and security [118-124]. System interconnections permit the participating companies to export and/or import electrical energy for mutual benefit. In addition, due to the diversity of load demands and the forced outages of generating equipment, each area can operate with less spinning reserve than would normally be required for isolated operation [120]. The actual assistance received through an interconnection is limited by the tie-line capacity and governed by the agreements among the participating organizations [124-128].

As noted above, system reliability is normally improved by interconnecting a system with another power system. Each interconnected system can then operate at a given risk level with a lower reserve than would be required without the interconnection [3]. This concept is discussed in Reference 3 in a planning context. The PJM method was extended by application to interconnected system evaluation in operational studies in [46,47]. Billinton and Chowdhury developed a unit commitment technique for interconnected systems based on the "two risk concept" where an interconnected system must satisfy the single system risk at the isolated level and also the interconnected system risk at the interconnected level. A technique called "expected energy assistance" is described in [48,49] to assess spinning reserve requirements in interconnected systems. This technique provides a feasible index for assessing assistance between interconnected systems.

A probabilistic technique is described in [60,61] for unit commitment in an isolated system and is presented in Chapter 2. This technique provides the system operator with measures of system well-being in the form of system health and margin in addition to the more conventional risk index. This chapter extends the concepts of unit commitment health analysis proposed in [60] to evaluate the spinning reserve requirements in interconnected systems. In order to determine the unit commitment in interconnected systems, the problem is decomposed into two subproblems corresponding to unit scheduling in each area in the isolated and interconnected modes. For the isolated mode, each area should commit generating units to satisfy its own operating criterion as described in Chapter 2. Once the required number of committed units in each area is determined, the next step is to satisfy the operating criterion associated with the overall interconnected system. An approach is illustrated in this chapter to determine the operating state probabilities to perform this task. Several factors affect the well-being of an interconnected system including the system peak loads, tie-line capabilities and system lead times. The IEEE-RTS is utilised in this chapter to provide numerical examples.

5.2 Representation of Interconnected System Well-being Model

The operating state framework is extended in this chapter to evaluate the required spinning reserve in an interconnected system. System well-being is considerably improved by interconnection with another power system. Each system can then operate at either the same or at a higher operating state level with a lower reserve than would be required without interconnection, as shown in Figure 5.1.

The overall interconnected system can be in the state of health if in addition to supplying the total demand, the outage of any single element, including any single generating unit and tie-line will not result in load curtailment in any of the pool members. In the interconnected marginal state, the total system demand is supplied, but the outage of any specific single element, i.e. a generating unit or a tie-line, will result in load curtailment in at least one of the areas. Some part of the total demand is curtailed in the interconnected risk state.

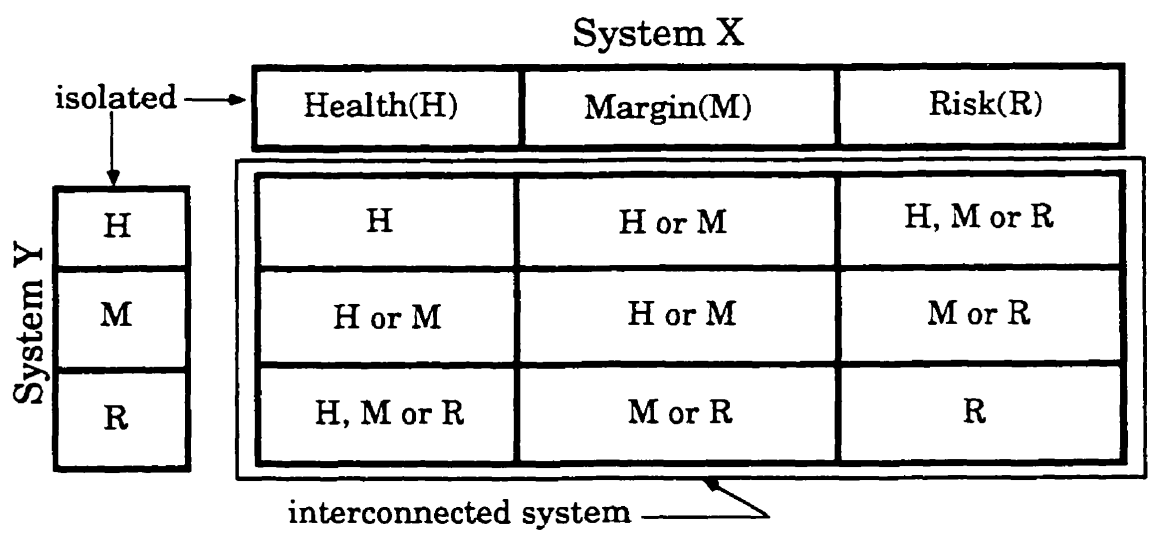

Figure 5.1: Possible operating states of the interconnected system.

It can be seen from Figure 5.1, that having the overall interconnected system in a specific operating state does not mean that all the pool members will be in this state when they are isolated. If both systems are initially operating in the marginal state, they can transfer to healthy state operation by virtue of being interconnected. This is an important benefit of interconnected systems. The performance of the overall interconnected system is quantified based on the three reliability indices designated as the interconnected healthy, marginal and risk state probabilities.

Unit commitment in an interconnected system can be done such that the specified operating criteria in both isolated and interconnected modes are satisfied.

5.3 Evaluation of Unit Commitment in Interconnected Systems

The interconnected systems unit commitment problem is decomposed into two subproblems in which unit scheduling is performed in each isolated system followed by interconnected system evaluation. The following notation is used:

$SP_h^{is,x}$, $SP_r^{is,x}$	Specified healthy and risk state probabilities for isolated System X,
$P_h^{is,x}$, $P_m^{is,x}$, $P_r^{is,x}$	Actual healthy, marginal and risk state probabilities for isolated System X,
$P_h^{in,x}$, $P_m^{in,x}$, $P_r^{in,x}$	Actual healthy, marginal and risk state probabilities of interconnected System X,
L_x	Load demand in System X and
t_x	Lead time of additional generating units in System X.

Similar notation is used for System Y. The unit commitment procedure is explained in more detail in the following subsections.

5.3.1 Unit Commitment in Isolated Systems

In this phase, generating units are committed to each isolated system to satisfy each operating criterion. The basic objective is to satisfy Equation 5.1.

$$P_r^{is,x} \leq SP_r^{is,x} \tag{5.1a}$$

$$P_r^{is,y} \leq SP_r^{is,y} \tag{5.1b}$$

If multiple criteria are used for each isolated system, then the probability of the healthy state in each system must also be at an acceptable level as shown in Equation 5.2. This will result in committing N_x and N_y units at isolated Systems X and Y respectively.

$$P_h^{is,x} \geq SP_h^{is,x} \tag{5.2a}$$

$$P_h^{is,y} \geq SP_h^{is,y} \tag{5.2b}$$

5.3.2 Unit Commitment in Interconnected Systems

Once the required number of committed units in each isolated system is determined, the next step is to satisfy the operating criteria associated with the overall interconnected system. The operating state probabilities of each interconnected system are then calculated using the area risk curve concept [3]. Figures 5.2a and 5.2b show the area risk curve for Systems X and Y respectively assuming that System X has a smaller lead time than System Y ($t_x < t_y$). The area risk curves for the two systems are discussed individually in the following two subsections.

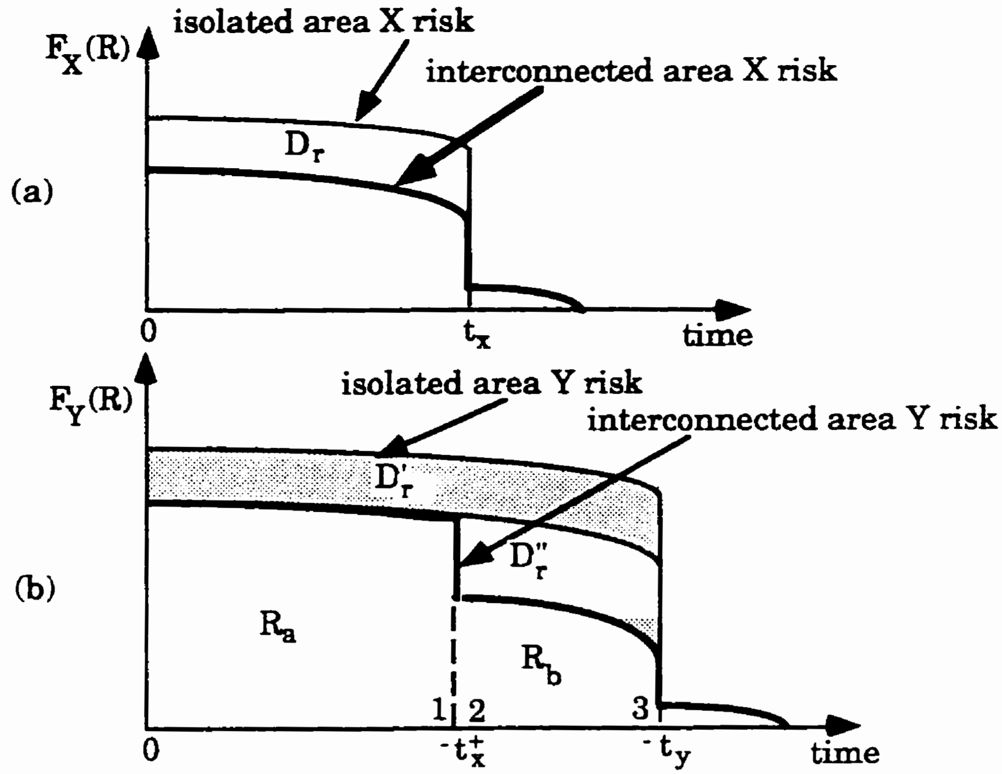

Figure 5.2: Area risk curves for Systems X and Y.

5.3.2.1 Operating Indices of Interconnected System X

The analysis of interconnected System X can be represented by the area risk curve shown in Figure 5.2a. The tie-line model is represented by Equation 5.3, where λ and μ are the failure and repair rates of the tie-line respectively. The repair time r is the reciprocal of μ.

$$P_d(t_x) = \begin{cases} \lambda \times t_x & t_x << r \\ \dfrac{\lambda}{\lambda+\mu} - \dfrac{\lambda}{\lambda+\mu} e^{-(\lambda+\mu)\times t_x} & otherwise \end{cases} \tag{5.3a}$$

$$P_u(t_x) = 1 - P_d(t_x) \tag{5.3b}$$

where $P_d(t_x)$ and $P_u(t_x)$ are the probabilities of the tie-line being in the down or up state at time t_x. Using the number of committed units in isolated System Y, the tie-line constrained assistance model [3] of System Y to System

X at the time t_x is determined. This model is indicated by vectors C_{yx} and P_{yx} in which C_{yx}^i and P_{yx}^i are the *ith* capacity available state and its associated probability.

$$C_{yx} = \left(C_{yx}^1, C_{yx}^2, \ldots, C_{yx}^i, \ldots, C_{yx}^l\right) \tag{5.4}$$

$$P_{yx} = \left(P_{yx}^1, P_{yx}^2, \ldots, P_{yx}^i, \ldots, P_{yx}^l\right) \tag{5.5}$$

where l is the number of capacity states in the tie constrained assistance model. The operating state probabilities of interconnected area X can be expressed as:

$$P_h^{in,x} = \sum_{i=1}^{l} (P_h^{is,x} | L_x - C_{yx}^i) \times P_{yx}^i \tag{5.6}$$

$$P_m^{in,x} = \sum_{i=1}^{l} (P_m^{is,x} | L_x - C_{yx}^i) \times P_{yx}^i \tag{5.7}$$

$$P_r^{in,x} = \sum_{i=1}^{l} (P_r^{is,x} | L_x - C_{yx}^i) \times P_{yx}^i \tag{5.8}$$

$$D_r = P_r^{is,x} - P_r^{in,x} \tag{5.9}$$

where $(P_h^{is,x} | L_x - C_{yx}^i)$ is the healthy state probability of the isolated system X with load of $L_x - C_{yx}^i$ and N_x units and D_r is the incremental decrease in the risk of system X due to interconnection with Y.

It should be noted that additional units are available to System X after the lead time of t_x and therefore the risk is negligible at that time (Figure 5.2a).

5.3.2.2 Operating Indices of Interconnected System Y

In this case, System X is the assisting system and System Y is the assisted one. The area risk curve for System Y is shown in Figure 5.2b which is divided into two different partial risks of R_a and R_b and three periods, i.e. 1,2 and 3.

The total interconnected area Y risk is the summation of the two partial risks, which are determined using operating state probabilities of different periods. The operating state probabilities in each period are calculated using N_y committed units in System Y and the available assistance from System X. The available assistance from System X to Y varies from period to period. In the first period (t_x^-), the assistance is determined based on N_x on-line committed units. In the second period (t_x^+), additional units become available in System X and therefore the assistance is found considering all available units at System X. The amount of assistance from System X to Y in the third period (t_y^-) is identical to that of the second period but the associated probabilities are different. All the calculations in the first two periods should be done at time t_x and those of the third period at time t_y. The operating state probabilities of interconnected System Y can be calculated using the following procedure.

$$P_r^{in,y} = R_a + R_b \tag{5.10}$$

$$R_a = P_{r1} \tag{5.11}$$

$$R_b = P_{r3} - P_{r2} \tag{5.12}$$

where P_{rk} is the probability of the risk state in period k of the area risk curve and is calculated using Equation 5.15. The tie-line constrained assistance model of System X to Y in each period is indicated by vectors C_{xy}^k and P_{xy}^k where C_{xy}^{ki} and P_{xy}^{ki} are the i^{th} capacity available state in the tie constrained assistance model and its associated probability at the k^{th} period in the area risk curve.

$$C_{xy}^k = (C_{xy}^{k1}, C_{xy}^{k2}, \ldots, C_{xy}^{ki}, \ldots, C_{xy}^{kl_k}) \qquad k = 1,2,3 \tag{5.13}$$

$$P_{xy}^k = (P_{xy}^{k1}, p_{xy}^{k2}, \ldots, P_{xy}^{ki}, \ldots, P_{xy}^{kl_k}) \qquad k = 1,2,3 \tag{5.14}$$

$$P_{rk} = \sum_{i=1}^{l_k} (P_r^{is,y} \big| L_y - C_{xy}^{ki}) \times P_{xy}^{ki} \tag{5.15}$$

where $(P_r^{is,y} | L_y - C_{xy}^{ki})$ is the probability of the risk state calculated for N_y units in System Y and a load level of $(L_y - C_{xy}^{ki})$ and l_k is the number of capacity states in the tie constrained assistance model in the k^{th} period.

From the area risk curve shown in Figure 5.2b, it can be seen that the incremental decrease in the risk of System Y due to interconnection with System X has the two parts of D'_r and D''_r. D'_r is the incremental decrease in the risk in System Y due to the assistance from System X based on only N_x on-line committed units. When t_x is less than t_y, additional units are available in System X after t_x and before t_y and therefore additional assistance is provided to System Y. The system risk further decreases by D''_r due to this additional assistance. The two parts of the incremental decrease in the risk and also the probabilities of the healthy and the marginal states of interconnected System Y can be calculated as follows.

$$P_r^{is,y} = R_a + R_b + D'_r + D''_r \tag{5.16}$$

Define;

$$\begin{aligned} P'_r &= 1 - P'_h - P'_m \\ &= R_a + R_b + D''_r \end{aligned} \tag{5.17}$$

where P'_h and P'_m are the probabilities of the healthy and marginal states calculated for N_y units in System Y including the assistance from System X due to only N_x committed units and at the time t_y.

$$D'_r = P_r^{is,y} - P'_r \tag{5.18}$$

$$P_r^{in,y} = 1 - P'_h - P'_m - D''_r \tag{5.19}$$

Adding and subtracting $(P'_h + P'_m)D''_r$ in the right side of Equation 5.19 and rearranging gives:

$$P_r^{in,y} = 1 - [\, P'_h (1 + D''_r) + P'_r \times D''_r \,] - P'_m (1 + D''_r) \\ = 1 - P_h^{in,y} - P_m^{in,y} \tag{5.20}$$

Then

$$P_h^{in,y} = P'_h (1 + D''_r) + P'_r \times D''_r \tag{5.21}$$

$$P_m^{in,y} = P'_m (1 + D''_r) \tag{5.22}$$

5.3.3 Overall Interconnected Operating State Probabilities

The operating state probabilities for the overall interconnected system are determined using the operating state probabilities of each interconnected system.

$$P_h^{in} = Min(P_h^{in,x}, P_h^{in,y}) \tag{5.23}$$

$$P_r^{in} = Max(P_r^{in,x}, P_r^{in,y}) \tag{5.24}$$

$$P_m^{in} = 1 - P_h^{in} - P_r^{in} \tag{5.25}$$

where P_h^{in}, P_m^{in} and P_r^{in} are the overall interconnected healthy, marginal and risk state probabilities respectively.

Equations 5.23 and 5.24 are valid only if the total scheduled capacity in each system is greater than its own load. The number of committed units in both systems are adequate to satisfy a specified interconnected risk SP_r^{in} if $P_r^{in} \leq SP_r^{in}$. Otherwise;

$$\text{if} \quad (P_r^{in,x} > P_r^{in,y}) \quad \text{then} \quad N_x = N_x + 1 \tag{5.26a}$$

$$\text{if} \quad (P_r^{in,y} > P_r^{in,x}) \quad \text{then} \quad N_y = N_y + 1 \tag{5.26b}$$

The criterion of satisfying a specified interconnected healthy state probability SP_h^{in} can also be added to the previous operating criterion. If

$P_h^{in} \geq SP_h^{in}$, then the number of generating units committed in Systems X and Y are considered to be adequate. Otherwise;

$$\text{if} \quad (P_h^{in,x} < P_h^{in,y}) \quad \text{then} \quad N_x = N_x + 1 \tag{5.27a}$$

$$\text{if} \quad (P_h^{in,y} < P_h^{in,x}) \quad \text{then} \quad N_y = N_y + 1 \tag{5.27b}$$

The procedure is continued until both the isolated and interconnected operating criteria are satisfied [129].

5.4 Application to the IEEE Reliability Test System

Table 5.1 shows the unit commitment for an isolated IEEE-RTS for two different cases. The lead time [3] is assumed to be 4 hours. In the first case, the system has to satisfy only a specified risk of 0.01, while in the second case multiple criteria are used in which the system is required to satisfy an acceptable healthy state probability of 0.9 in addition to satisfying a specified risk of 0.01 [60]. The isolated system results presented in Table 5.1 are provided to facilitate comparison with those of Table 5.3.

Table 5.1. Unit commitment in an isolated IEEE-RTS.

Load	CASE 1			CASE 2		
MW	Units	Health	Risk	Units	Health	Risk
1140	8	0.9771957	0.0001413	8	0.9771957	0.0001413
1425	10	0.9768473	0.0001727	10	0.9768473	0.0001727
1710	11	0	0.0073941	12	0.9687194	0.0002327
1995	13	0.9569165	0.0003625	13	0.9569165	0.0003625
2280	15	0	0.0074509	16	0.9542422	0.0003969
2565	18	0	0.0074830	19	0.9395823	0.0005400
2850	24	0	0.0077191	28	0.9191692	0.0007186

The technique proposed in the previous section was applied to two interconnected IEEE-RTS to evaluate the required spinning reserve in the interconnected system. The two identical IEEE-RTS have been designated as System X and System Y and are connected through the two tie-lines described in Table 5.2.

Table 5.2. Tie-line data.

No. of tie-lines	Capacity [MW]	Repair time [hr]	Failure rate [occ/yr]
2	100	8	1

Table 5.3 shows the unit commitment in the two interconnected systems when additional units in each system have a lead time of 4 hours. In addition to the previously noted isolated system operating criterion, a specified interconnected risk of 0.001 and an acceptable interconnected healthy state probability of 0.9 are applied. The load demand in both systems are identical and therefore the operating state probabilities of each system in the interconnected mode are identical to those of the overall interconnected system.

Table 5.3. Unit commitment and operating state probabilities of the interconnected system.

Load* [MW]	No. of units*	Overall interconnected indices		
		Health	Margin	Risk
1140	8	0.98914764	0.01081275	0.00003960
1425	10	0.98922569	0.01073530	0.00003901
1710	11	0.96954485	0.03027064	0.00018451
1995	13	0.98857934	0.01137523	0.00004544
2280	15	0.96916642	0.03064441	0.00018917
2565	18	0.96544228	0.03433919	0.00021853
2850	24	0.94988028	0.04978234	0.00033738

* load and number of committed units in both System X and Y

The number of committed units in Table 5.3 is identical to that shown in Case 1 of Table 5.1, where the probability of the healthy state is zero for some load levels due to insufficient spinning reserve. By interconnecting the two systems, the overall system has an acceptable healthy state probability without committing any additional generating units. The required number of committed units usually decreases when two systems are interconnected. This can clearly be seen by comparing Table 5.3 with Case 2 in Table 5.1. An isolated IEEE-RTS should commit at least 28 units at a load level of 2850 MW to satisfy a healthy state probability of 0.9. It, however, needs only 24 units at the same load level when connected to an identical system.

Figures 5.3 and 5.4 show the required number of committed units and the operating state probabilities for three different studies. In the first study (S1), unit commitment is done in an isolated IEEE-RTS such that a specified risk of 0.01 and healthy state probability of 0.9 are satisfied. In the second study (S2), two identical IEEE-RTS are interconnected where unit commitment is done such that each system satisfies a single criterion, i.e. a specified risk of 0.01, in the isolated mode and multiple criteria, i.e. a

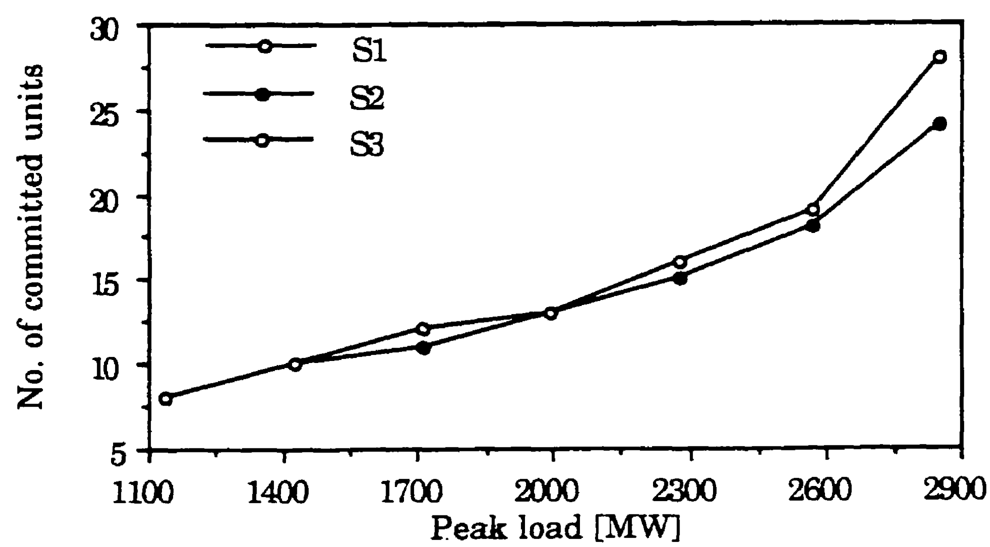

Figure 5.3: Number of committed units for the three studies, S1, S2, S3.

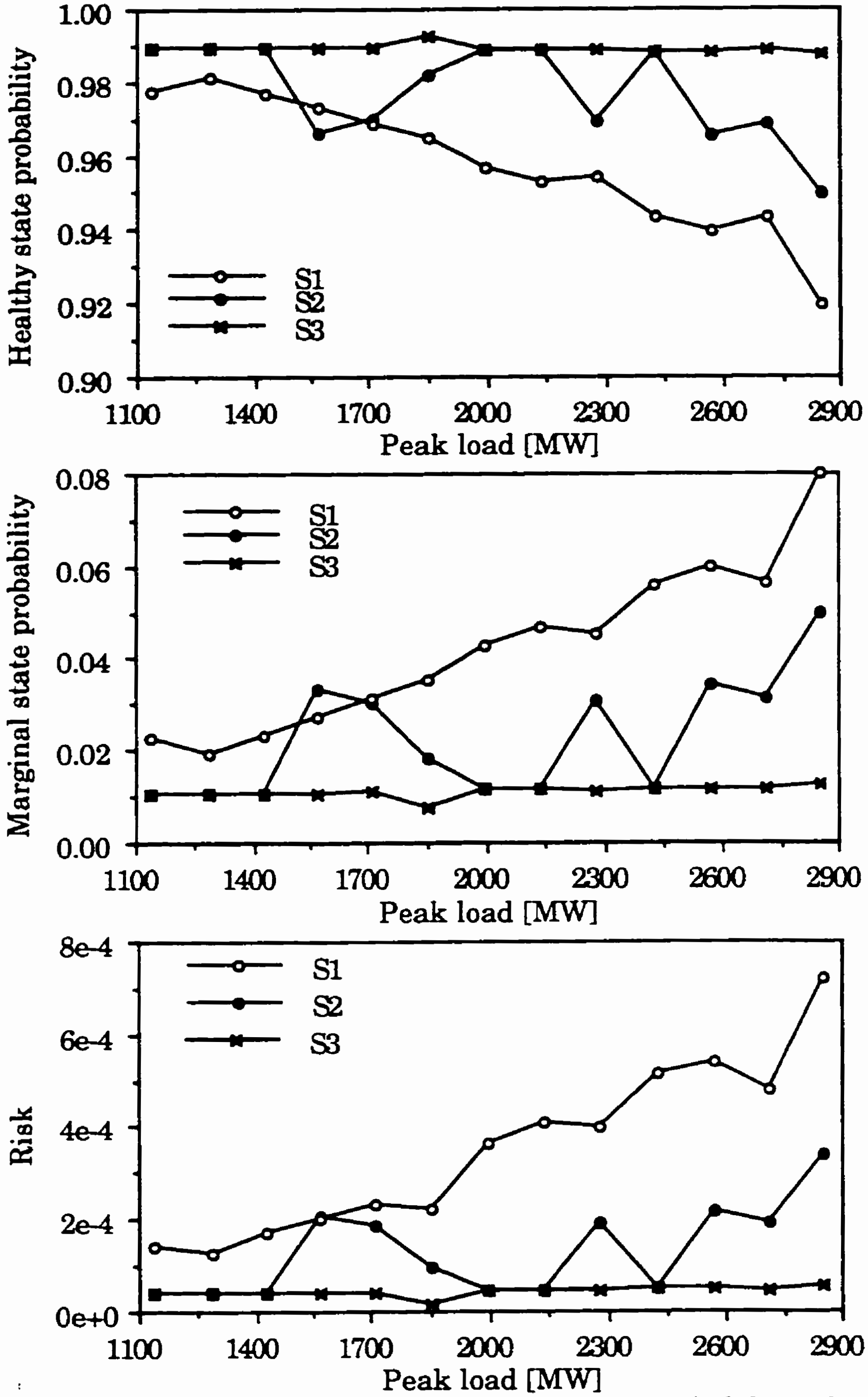

Figure 5.4: Unit commitment and operating state probabilities for the three studies, S1, S2, S3.

specified risk of 0.001 and healthy state probability of 0.9, in the interconnected mode. Multiple criteria are applied in both the isolated and interconnected modes in the third study (S3). It can be seen from Figure 5.4 that, the highest healthy state probabilities occur in the third study for all the load levels . The benefits derived by interconnection can be recognized by comparing the results of S1 with those of S2 in which higher healthy state probabilities and lower risks are achieved with lower spinning reserves.

Unit commitment health analysis in interconnected systems depends on different factors such as operating criteria, system peak loads, lead times, tie-line carrying capabilities, failure rates, load forecast uncertainty and postponable outages etc.. The impact of some of these factors is discussed in the following subsections.

5.4.1 Effect of Load Variation

In the studies presented in the previous section, it was assumed that both systems have the same load level. Table 5.4 shows the operating indices of interconnected Systems X and Y where System X has a fixed load level of 2280 MW while the load in System Y varies from 1140 MW to 2850 MW. Both systems should satisfy a single and multiple operating criteria in the isolated and interconnected modes respectively. Compared to the results shown in Table 5.3, it can be seen that the operating state probabilities are affected as the load in the two interconnected systems varies. This is due to the changes in the available assistance between the two systems.

5.4.2 Effect of Tie Line Transfer Capability

One of the most important factors influencing interconnected system operating state probabilities is the tie-line capabilities. Figure 5.5 shows the

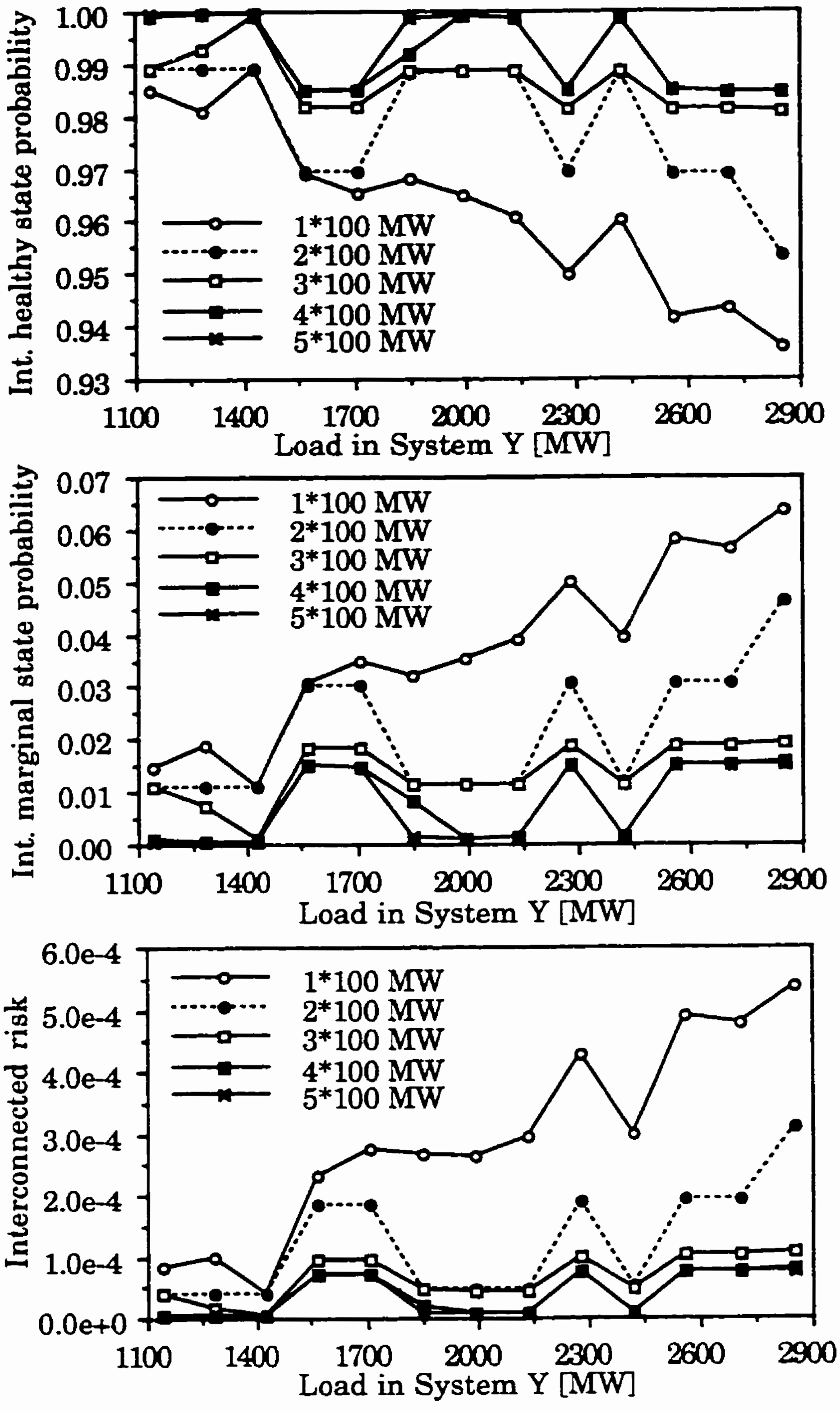

Figure 5.5: Effect of tie-line capability.

variation in the operating state probabilities of System Y when it is connected to System X with two tie-lines. The transfer capability of each tie-line varies from 50 MW to 250 MW. System X has a fixed load of 1995 MW with 13 committed units, while the load in System Y is changed from 1140 to 2850 MW. The required number of committed units in System Y are the same as those shown in Table 4.4. The degree of well-being in System Y is significantly improved by increasing the tie-line capabilities. System X has a total spinning reserve of 411 MW and virtually no gain is obtained by increasing the total tie-line capability to more than 400 MW.

5.4.3 Effect of Lead Time Variation

In the previous studies it was assumed that both systems have the same lead time of 4 hours. Table 5.5 shows the results when lead times of additional generation in Systems X and Y are 2 and 4 hours respectively. The required number of committed units in System X decreases compared to that shown in Table 5.3. Systems X and Y with 20 and 24 units respectively and at the load level of 2850 MW have an isolated healthy state probability of zero. They, however, have acceptable healthy state probabilities without committing any additional units when interconnected.

5.4.4 Effect of Load Forecast Uncertainty

The basic concepts of load forecast uncertainty are illustrated in Section 3.5.4. Assume that the load forecast deviation in Systems X and Y is normally distributed with n and m discrete load steps respectively. In order to determine the operating state indices there are $n*m$ health, margin and risk probability levels for Systems X and Y where n and m are the discrete load steps in the uncertainty models for Systems X and Y respectively. The

Table 5.4: Impact of load variation on the unit commitment and operating state probabilities.

Peak load		No. of units		Spin. res.		System X indices in Interconnected mode			System Y indices in Interconnected mode		
X	Y	X	Y	X	Y	Health	Margin	Risk	Health	Margin	Risk
2280	1140	15	8	381	407	0.95717875	0.04248827	0.00033298	0.98904848	0.01091088	0.00004064
2280	1425	15	10	381	516	0.96042545	0.03928478	0.00028977	0.98909218	0.01086737	0.00004046
2280	1710	15	11	381	386	0.95707731	0.04258877	0.00033392	0.96773125	0.03206990	0.00019885
2280	1995	15	13	381	411	0.95692885	0.04273596	0.00033519	0.98807438	0.01187535	0.00005027
2280	2280	15	15	381	381	0.95679051	0.04287316	0.00033634	0.96718332	0.03261175	0.00020493
2280	2565	15	18	381	372	0.95653223	0.04312904	0.00033873	0.96678440	0.03300571	0.00020990
2280	2850	15	24	381	351	0.95627346	0.04338569	0.00034085	0.94999578	0.04966984	0.00033438

Table 5.5: Unit commitment and operating state probabilities in the two interconnected IEEE-RTS with unequal lead times.

Peak load		Units Iso.		Units Int.		System X indices in Interconnected mode			System Y indices in Interconnected mode		
X	Y	X	Y	X	Y	Health	Margin	Risk	Health	Margin	Risk
1140	1140	7	8	7	8	0.98485242	0.01509224	0.00005534	0.98908917	0.01087201	0.00003887
1425	1425	8	10	9	10	0.99037848	0.00958930	0.00003248	0.98909634	0.01086482	0.00003916
1710	1710	10	11	10	11	0.97860382	0.02130696	0.00008923	0.96611063	0.03373927	0.00015016
1995	1995	12	13	12	13	0.97845240	0.02145134	0.00009626	0.98806779	0.01188906	0.00004320
2280	2280	14	15	14	15	0.97434204	0.02553920	0.00011877	0.96530554	0.03454040	0.00015412
2565	2565	17	18	17	18	0.96945180	0.03041146	0.00013674	0.96490831	0.03493503	0.00015671
2850	2850	20	24	20	24	0.95651874	0.04328673	0.00019452	0.93744253	0.06225856	0.00029897

operating state indices in each case are weighted by the probability of the simultaneous load conditions and the summations of these indices are the expected health, margin and risk probabilities for each system in the interconnected mode.

$$P_h^{in,x} = \sum_{i=1}^{n} \sum_{j=1}^{m} P_h^{in,x}(L_x^i, L_y^j) \times P_x(i) \times P_y(j) \tag{5.28}$$

where

$P_h^{in,x}$	Expected healthy state probability in System X.
$P_h^{in,x}(L_x^i, L_y^j)$	Probability of the healthy state in the interconnected system X for *ith* load step of the load distribution in system X and *jth* load step of the load distribution in system Y.
$P_x(i)$	Probability of the *ith* load step of the load distribution in system X.
$P_y(i)$	Probability of the *jth* load step of the load distribution in system Y.

The expected interconnected marginal and risk state probabilities are calculated using the same method. A similar expression can also be written for the operating indices of interconnected System Y.

Unit commitment and the associated operating state probabilities in Systems X and Y for zero load forecast error are shown in Table 5.4. Table 5.6 shows the results assuming that the load forecast deviation in System X is normally distributed with a standard deviation of 4% of the forecast peak load using the 7 step histogram shown in Figure 3.8. The peak load in System Y was varied from 40% to 100% of the system peak load of 2850 MW with zero uncertainty. The overall interconnected system indices are shown in Table 5.7. Comparing the results shown in Table 5.4 with those shown in Table 5.6, it can be seen that the interconnected healthy state probability

Table 5.6: Operating indices of Systems X and Y with 4% LFU in System X and 0 LFU in System Y.

Peak load		No. of units		Spin. res.		System X indices in interconnected mode			System Y indices in interconnected mode		
X	Y	X	Y	X	Y	Health	Margin	Risk	Health	Margin	Risk
2280	1140	15	8	381	407	0.90505406	0.09422052	0.00072542	0.98905310	0.01090638	0.00004052
2280	1425	15	10	381	516	0.91014826	0.08917579	0.00067595	0.98909380	0.01086579	0.00004040
2280	1710	15	11	381	386	0.90499267	0.09428084	0.00072649	0.96955974	0.03025509	0.00018517
2280	1995	15	13	381	411	0.90494436	0.09433188	0.00072376	0.98816674	0.01178399	0.00004927
2280	2280	15	15	381	381	0.90489324	0.09437922	0.00072754	0.96903092	0.03077770	0.00019138
2280	2565	15	18	381	372	0.90484868	0.09442337	0.00072795	0.96870305	0.03110194	0.00019501
2280	2850	15	24	381	351	0.90340855	0.09585219	0.00073925	0.95091217	0.04875937	0.00032846

Table 5.7: Overall interconnected indices with 4% LFU in System X and 0 LFU in System Y.

Peak load		No. of units		Overall interconnected indices		
X	Y	X	Y	Health	Margin	Risk
2280	1140	15	8	0.90505406	0.09422052	0.00072542
2280	1425	15	10	0.91014826	0.08917579	0.00067595
2280	1710	15	11	0.90499267	0.09428084	0.00072649
2280	1995	15	13	0.90494436	0.09433188	0.00072376
2280	2280	15	15	0.90489324	0.09437922	0.00072754
2280	2565	15	18	0.90484868	0.09442337	0.00072795
2280	2850	15	24	0.90340855	0.09585219	0.00073925

decreases for both systems with load forecast uncertainty in System X. This change is more obvious for System X. The interconnected risk state probabilities, however, increase in both systems. The overall interconnected system health indices decrease by including load forecast uncertainty.

5.4.5 Effect of Postponable Outages

Table 5.8 shows unit commitments and the associated operating indices in two isolated Systems X and Y. In these studies, the committed generating units in System X have a degree of postponability of 0.5 and the degree of postponability in System Y is considered to be zero. By comparing the results shown in Table 5.8 with those of Table 5.1 (Case 1), it can be seen that the number of committed units in System X decreases from 15 to 14 for the same operating criterion. Table 5.9 shows the unit commitment and operating health, margin and risk probabilities for both systems when they are interconnected. The operating criterion is that a specified risk of 0.001 and an acceptable healthy state probability of 0.9 must be satisfied in the interconnected mode in addition to satisfying a specified risk of 0.01 in the

Table 5.8. Operating indices of isolated Systems X and Y with β of 0.5 in System X and 0 in System Y.

Peak load		Isolated system X indices			Isolated system Y indices		
X	Y	Units	Health	Risk	Units	Health	Risk
2280	1140	14	0.0	0.0092020	8	0.97719573	0.00014127
2280	1425	14	0.0	0.0092020	10	0.97684725	0.00017271
2280	1710	14	0.0	0.0092020	11	0.0	0.00739406
2280	1995	14	0.0	0.0092020	13	0.95691649	0.00036247
2280	2280	14	0.0	0.0092020	15	0.0	0.00745092
2280	2565	14	0.0	0.0092020	18	0.0	0.00748301
2280	2850	14	0.0	0.0092020	24	0.0	0.00771909

isolated mode. In this case, System X is required to commit 15 units to satisfy the operating criteria. By comparing the results shown in Table 5.9 with those in Table 5.4, it can be seen that the healthy state probabilities increase and the system risk decreases due to the inclusion of postponable outages.

The required number of committed units and also the operating state probabilities are affected by the degree of postponability. Table 5.10 shows the effects on the unit commitment and the operating state probabilities of variation in the degree of postponability. System X has a load level of 2565 MW and the load level in System Y is considered to be 1995 MW. It can be seen from Table 5.10 that for the same number of committed units, the system health probability increases and the system risk decreases as the degree of postponability increases.

5.4.6 Effect of Derated States

In order to illustrate the effect of generating unit derated states, the 400 MW and the 350 MW units in each system were given 50% derated states. The identical systems are interconnected. The required number of committed units in the isolated and interconnected modes and the overall interconnected system operating state probabilities are shown in Table 5.11. The system well-being for a given load level, is improved by considering derated states. In general, the required number of committed units decreases by including derated states. This can be seen by comparing the results shown in Table 5.3 with those of Table 5.11.

Table 5.9: Operating indices of interconnected Systems X and Y with β of 0.5 in System X and 0 in System Y.

Peak load		No. of units		Spin. res.		System X indices in interconnected mode			System Y indices in interconnected mode		
X	Y	X	Y	X	Y	Health	Margin	Risk	Health	Margin	Risk
2280	1140	15	8	381	407	0.96932278	0.03048925	0.00018797	0.98906625	0.01089354	0.00004020
2280	1425	15	10	381	516	0.97618129	0.02368167	0.00013704	0.98911861	0.01084115	0.00004024
2280	1710	15	11	381	386	0.96922810	0.03058322	0.00018868	0.96948736	0.03032769	0.00018495
2280	1995	15	13	381	411	0.96919630	0.03061477	0.00018893	0.98839716	0.01155605	0.00004679
2280	2280	15	15	381	381	0.96916642	0.03064441	0.00018917	0.96916642	0.03064441	0.00018917
2280	2565	15	18	381	372	0.96912661	0.03068389	0.00018949	0.96895467	0.03085326	0.00019207
2280	2850	15	24	381	351	0.96561897	0.03416512	0.00021591	0.95131518	0.04835843	0.00032638

Table 5.10: Operating indices of interconnected Systems X and Y with variation of β from 0 to 1 in System X and 0 in System Y.

β	Peak load		Units Iso.		Units Int.		System X indices in interconnected mode			System Y indices in interconnected mode		
	X	Y	X	Y	X	Y	Health	Margin	Risk	Health	Margin	Risk
0.0	2565	1995	18	13	18	13	0.96897562	0.03083263	0.00019175	0.98839916	0.01155400	0.00004685
0.1	2565	1995	18	13	18	13	0.97054390	0.02927656	0.00017954	0.98842619	0.01152720	0.00004661
0.2	2565	1995	18	13	18	13	0.97211408	0.02771855	0.00016737	0.98845322	0.01150040	0.00004638
0.3	2565	1995	18	13	18	13	0.97368616	0.0261586	0.00015525	0.98848026	0.0114736	0.00004615
0.4	2565	1995	17	13	17	13	0.94586408	0.05371246	0.00042345	0.98803215	0.01191812	0.00004973
0.5	2565	1995	17	13	17	13	0.94739247	0.05220866	0.00039887	0.98807298	0.01187767	0.00004935
0.6	2565	1995	17	13	17	13	0.94892270	0.05070215	0.00037515	0.98811385	0.01183719	0.00004896
0.7	2565	1995	17	13	17	13	0.95045478	0.04919292	0.00035229	0.98815476	0.01179666	0.00004858
0.8	2565	1995	17	13	17	13	0.95198871	0.04768098	0.0003303	0.98819571	0.01175610	0.00004819
0.9	2565	1995	16	13	17	13	0.95352450	0.04616653	0.00030918	0.9882369	0.01171551	0.00004781
1.0	2565	1995	16	13	17	13	0.95506214	0.04464916	0.00028892	0.98827792	0.01167487	0.00004742

Table 5.11: Required number of committed units and the overall interconnected indices considering derated states in both Systems X and Y.

Peak load [MW]	No. of Units		Overall interconnected indices		
	Iso.	Int.	Health	Margin	Risk
1140	7	7	0.96212132	0.03772980	0.00014888
1425	9	9	0.97544961	0.02444668	0.00010371
1710	10	10	0.94566067	0.05408348	0.00025585
1995	12	12	0.93753505	0.06216254	0.00030241
2280	14	14	0.93719088	0.06252004	0.00028908
2565	17	17	0.92922155	0.07045872	0.00031974
2850	20	21	0.95333316	0.04646731	0.00019995

5.5 Conclusions

This chapter extends the concepts of unit commitment health analysis presented in Chapter 2 to evaluate the spinning reserve requirements in interconnected power systems. Unit commitment is done such that the operating criteria at both the isolated and interconnected modes are satisfied by the pool members. A procedure is illustrated in this chapter to determine the operating state probabilities for the overall interconnected system. The results presented show that system well-being can be considerably improved by interconnection with another system. Each system can operate at either the same or at a higher operating state level with a lower reserve than would be required without interconnection. A number of studies using the IEEE-RTS are illustrated to evaluate the impact on the interconnected system well-being of factors such as peak load, lead time and tie-line capabilities, load forecast uncertainty, degree of postponability and derated states.

Under normal operating conditions, the generating capacity in operation is greater than the firm load and with this number of committed units, the system may also be able to carry a limited amount of interruptible load on top of the firm load without violating the operating criterion. The concepts associated with the determination of this additional interruptible load in both isolated and interconnected systems are presented in the next chapter.

6. OPTIMUM INTERRUPTIBLE LOAD CARRYING CAPABILITY IN ISOLATED AND INTERCONNECTED SYSTEMS

6.1 Introduction

Considerable attention is being devoted to demand side options, such as interruptible loads, as alternatives to constructing new power plants. This ability to interrupt load is sometimes referred to as direct load control [36,130-135]. Reference 36 defines interruptible load as a demand that can be interrupted within a specified period of time by direct action of the supplying system in accordance with contractual provisions. A relatively short notice is normally issued by the operator prior to the power interruption. This time period is designated as the interruptible lead time. In this process, the designated loads can normally be disconnected for up to a certain number of times and/or an aggregate length of time in a year. It may also be necessary to curtail load due to sudden operating unit outages [38,39], in addition to production cost optimization requirements [136-139]. The monetary impacts of interruption are lower for some customers than for others. In these cases, there are economic benefits for both the utility and the customer which lead to equitable tariff reductions [134]. Interruptible loads are sometimes considered by utilities as part of the operating reserve and included as 10-minute reserve in the system operating plan [51,140].

A power system must commit a certain number of available generating units to satisfy the system load. The system operator must determine what is the maximum load level that can be supplied by the given number of committed units. This is referred to as the firm load carrying capability (FLCC) of the committed generation. Under normal operating conditions, the generating capacity in operation is greater than the minimum requirement and with this number of committed units, the system may also be able to carry a limited amount of interruptible load on top of the firm load without violating the operating criterion. Under these conditions, a larger system load can be served without committing additional units other than those required to carry the firm load. This additional load must be capable of interruption at short notice if required. The capability of a system to serve the additional interruptible load is designated as the system interruptible load carrying capability (ILCC). This chapter presents a probabilistic technique to evaluate the ILCC in both isolated and interconnected generation systems. A set of ILCC is determined for a given number of committed units and the associated FLCC, which consists of different amounts of interruptible load and the associated lead times. The condition is then formulated as an optimization problem. The optimum ILCC (OILCC) is selected from the set of system ILCC levels. The objective in this formulation is to determine the amount of interruptible load and the associated lead time that will maximize the expected energy supplied within the system lead time while satisfying the operating criteria [141]. The operating criteria are defined using the system well-being framework presented in Chapter 2.

6.2 Well-being Indices Including Interruptible Load

Interruptible load can be incorporated in operating reserve assessment using the area risk curve technique [3]. The inclusion of interruptible load in operating reserve assessment in isolated generating systems is illustrated in [61]. Unit commitment in interconnected systems is examined in Chapter 5 considering only spinning reserve. Interruptible load can be included as part of the interconnected system operating reserve using area risk curve concepts. Typical area risk curves for isolated and interconnected systems are shown in Figure 6.1 using the following symbols.

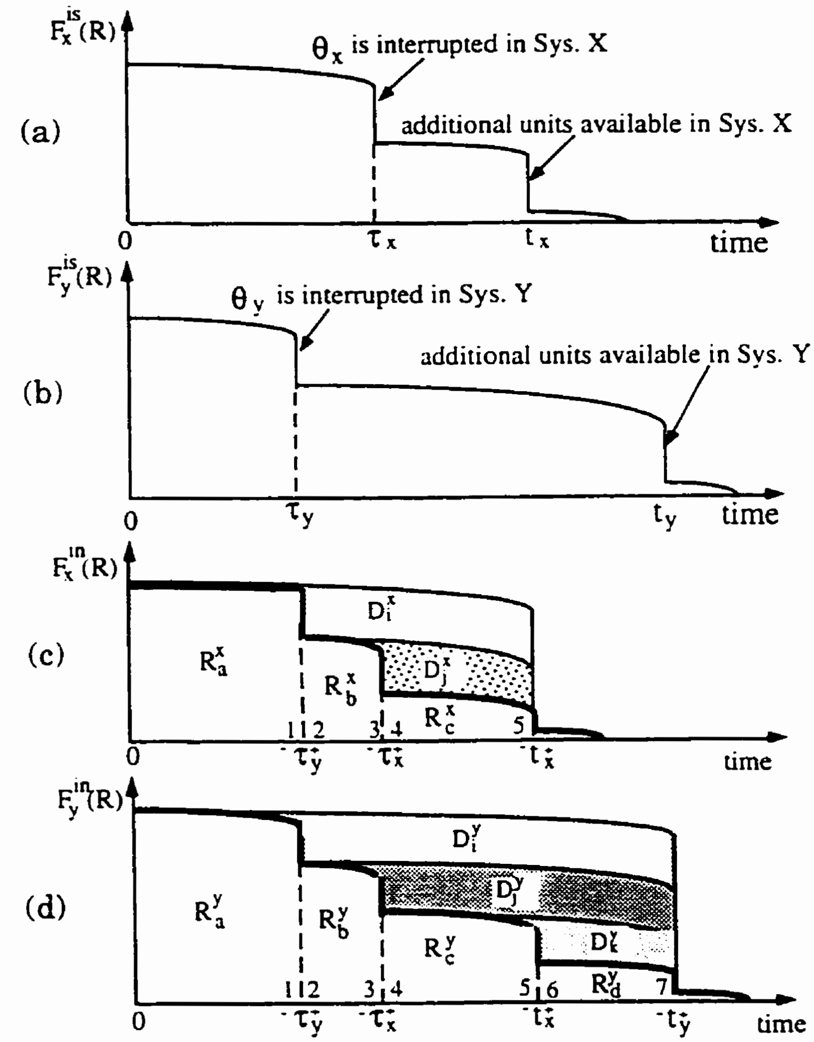

Figure 6.1: Isolated *(is)* and interconnected *(in)* area risk curve of Systems X and Y.

$F_x^{in}(R)$, $F_y^{in}(R)$ Interconnected area risk function of Systems X and Y respectively,

$F_x^{is}(R)$, $F_y^{is}(R)$ Isolated area risk function of Systems X and Y respectively,

τ_x, τ_y Interruption times in Systems X and Y,

θ_x, θ_y Interruptible loads in Systems X and Y,

t_x, t_y Lead time of additional generating units in Systems X and Y respectively,

D_i^x, D_j^x Decreased risk in interconnected System X due to the inclusion of interruptible load in Systems Y and X respectively,

D_i^y, D_j^y Decreased risk in interconnected System Y due to the inclusion of interruptible load in Systems Y and X respectively,

D_k^y Decreased risk in interconnected System Y due to the availability of additional assistance from System X,

Figure 6.1c shows the interconnected area risk of System X in detail, in which System X is assisted by System Y. This figure contains three different partial risks, R_a^x, R_b^x and R_c^x and five periods. The partial risks are determined using the operating state probabilities associated with the different periods. The operating state probabilities in each period depend on the assisted system load, the available assistance from the other system and the time associated with that period. All the calculations in each period must be done at the corresponding time. In Period 1, System X has a load of L_x and the assistance from System Y is determined based on a load level of L_y. The system risk decreases by D_i^x as θ_y MW of load is interrupted in System Y for Period 2. The reason for this is that the available assistance from System Y to X increases compared to that for Period 1. The conditions for Period 3 are the same as those for Period 2 except for the time of calculation. The system risk further decreases by D_j^x as θ_x MW of load is interrupted in System X for

Period 4. The conditions for Period 5 are identical to those for Period 4 except for the time of calculation. At time t_x^+, additional generating units are available in System X and the system risk is considered to be negligible after this time.

$$P_r^{in,x} = R_a^x + R_b^x + R_c^x \tag{6.1}$$

$$R_a^x = P_{r1}^x \tag{6.2}$$

$$R_b^x = P_{r3}^x - P_{r2}^x \tag{6.3}$$

$$R_c^x = P_{r5}^x - P_{r4}^x \tag{6.4}$$

Consider that the tie-line constrained assistance model of System Y to X for the k_{th} period is indicated by vectors C_{yx}^k and P_{yx}^k. The partial risk at each period P_{rk}^x is calculated using the conditional probability approach. C_{yx}^k is determined based on L_y and $L_y - \theta_y$ MW load in System Y at Periods 1 and 2 to 5 respectively.

$$C_{yx}^k = (C_{yx}^{k1}, C_{yx}^{k2}, \ldots, C_{yx}^{ki}, \ldots, C_{yx}^{kn_{ky}}) \quad k = 1 \text{ to } 5 \tag{6.5}$$

$$P_{yx}^k = (P_{yx}^{k1}, P_{yx}^{k2}, \ldots, P_{yx}^{ki}, \ldots, P_{yx}^{kn_{ky}}) \quad k = 1 \text{ to } 5 \tag{6.6}$$

$$P_{rk}^x = \sum_{i=1}^{n_{ky}} (P_r^{is,x} \big| LP_x^k - C_{yx}^{ki}) \times P_{yx}^{ki} \tag{6.7}$$

where $(P_r^{is,x} \big| LP_x^k - C_{yx}^{ki})$ is the probability of the risk state calculated for N_x committed units in System X and a load level of $(LP_x^k - C_{yx}^{ki})$. LP_x^k is equal to L_x for Periods 1, 2 and 3. It is, however, decreased to $L_x - \theta_x$ for Periods 4 and 5. The healthy and marginal state probabilities of interconnected system X are calculated as follows:

$$P'_{rx} = P_r^{in,x} + D_i^x + D_j^x \tag{6.8}$$

$$= 1 - P'_{hx} - P'_{mx} \tag{6.9}$$

$$TD_x = D_i^x + D_j^y \tag{6.10}$$

$$P_r^{in,x} = 1 - P'_{hx} - P'_{mx} - TD_x \tag{6.11}$$

$$P_r^{in,x} = 1 - P'_{hx} - P'_{mx} - TD_x + (P'_{hx} + P'_{mx}) \times TD_x - (P'_{hx} + P'_{mx}) \times TD_x \tag{6.12}$$

$$= 1 - [P'_{hx}(1 + TD_x) + P'_{rx} \times TD_x] - P'_{mx} \times TD_x \tag{6.13}$$

$$= 1 - P_h^{in,x} - P_m^{in,x} \tag{6.14}$$

$$P_h^{in,x} = P'_{hx}(1 + TD_x) + P'_{rx} \times TD_x \tag{6.15}$$

$$P_m^{in,x} = P'_{mx} \times (1 + TD_x) \tag{6.16}$$

where

C_{yx}^{ki}, P_{yx}^{ki}	i_{th} capacity state and its associated probability in the tie-lie constrained assistance model of System Y to X for the k_{th} period of area risk curve $F_x^{in}(R)$,
n_{ky}	Number of capacity states in the tie-line constrained assistance model of System Y to X for the k_{th} period of area risk curve $F_x^{in}(R)$,
$P'_{hx}, P'_{mx}, P'_{rx}$	Healthy, marginal and risk state probabilities of interconnected System X calculated at lead time of t_x, N_x units in System X, N_y units in System Y and considering no interruptible load in the two systems,
$P_h^{in,x}$, $P_m^{in,x}$, $P_r^{in,x}$	Healthy, marginal and risk state probabilities of interconnected System X,
LP_x^k	Load level in Systems X at the k_{th} period.
TD_x	Total decreased risk in System X,

The interconnected area Y risk curve is shown in more detail in Figure 6.1d, where System Y is assisted by System X. It can be seen from the figure that the system risk decreases by D_i^y and D_j^y due to the inclusion of interruptible load in Systems Y and X respectively. The system risk further decreases by D_k^y for Period 6. The reason for this is that additional units become available in System X at the lead time of t_x^+ and therefore the available assistance from System X to Y increases. The area risk curve consists of four partial risks which can be determined using the calculated risk in the seven different periods.

$$P_r^{in,y} = R_a^y + R_b^y + R_c^y + R_d^y \tag{6.17}$$

$$R_a^y = P_{r1}^y \tag{6.18}$$

$$R_b^y = P_{r3}^y - P_{r2}^y \tag{6.19}$$

$$R_c^y = P_{r5}^y - P_{r4}^y \tag{6.20}$$

$$R_d^y = P_{r7}^y - P_{r6}^y \tag{6.21}$$

$$C_{xy}^k = (C_{xy}^{k1},\ C_{xy}^{k2}, \ldots,\ C_{xy}^{ki}, \ldots,\ C_{xy}^{kn_{kx}}) \quad k = 1 \text{ to } 7 \tag{6.22}$$

$$P_{xy}^k = (P_{xy}^{k1},\ P_{xy}^{k2}, \ldots,\ P_{xy}^{ki}, \ldots,\ P_{xy}^{kn_{kx}}) \quad k = 1 \text{ to } 7 \tag{6.23}$$

$$P_{rk}^y = \sum_{i=1}^{n_{kx}} (P_r^{is,y} \big| LP_y^k - C_{xy}^{ki}) \times P_{xy}^{ki} \tag{6.24}$$

It should be noted that the assistance from System X to Y for the Periods 1 to 5 is calculated based on N_x units and for the Periods 6 and 7 based on the total number of units in System X with the lead time of t_x. D_k^y becomes zero if the two systems have identical lead times. The interconnected healthy and marginal state probabilities of System Y are calculated as follows:

$$P'_{ry} = P_r^{in,y} + D_i^y + D_j^y + D_k^y \tag{6.25}$$

$$= 1 - P'_{hy} - P'_{my} \tag{6.26}$$

$$TD_y = D_i^y + D_j^y + D_k^y \tag{6.27}$$

$$P_r^{in,y} = 1 - P'_{hy} - P'_{my} - TD_y \tag{6.28}$$

Adding and subtracting the term $(P'_{hy} + P'_{my}) \times TD_y$ on the right-hand side of Equation 6.28 and combining with common coefficients gives:

$$P_r^{in,y} = 1 - [P'_{hy}(1 + TD_y) + P'_{ry} \times TD_y] - P'_{my} \times (1 + TD_y) \tag{6.29}$$

$$= 1 - P_h^{in,y} - P_m^{in,y} \tag{6.30}$$

$$P_h^{in,y} = P'_{hy}(1 + TD_y) + P'_{ry} \times TD_y \tag{6.31}$$

$$P_m^{in,y} = P'_{my} \times (1 + TD_y) \tag{6.32}$$

where

P_{rk}^{y}	Risk of k_{th} period in the area risk curves of Systems X and Y respectively,
C_{xy}^{ki}, P_{xy}^{ki}	i_{th} capacity state and its associated probability in the tie-lie constrained assistance model of System X to Y for the k_{th} period of area risk curve $F_y^{in}(R)$,
n_{kx}	Number of capacity states in the tie-line constrained assistance model of System X to Y for the k_{th} period of area risk curve $F_y^{in}(R)$,
LP_y^k	Load level in System Y at the k_{th} period,
$P'_{hy}, P'_{my}, P'_{ry}$	Healthy, marginal and risk state probabilities of interconnected System Y calculated at lead time of t_y, N_x units in System X, N_y units in System Y and considering no interruptible load in the two systems,
$P_h^{in,y}$, $P_m^{in,y}$, $P_r^{in,y}$	Healthy, marginal and risk state probabilities of interconnected System Y,

Once the operating indices of each system in the interconnected mode are calculated, the next step is to determine the overall interconnected well-being indices [129].

$$P_h^{in} = Min(P_h^{in,x}, P_h^{in,y}) \tag{6.33}$$

$$P_r^{in} = Max(P_r^{in,x}, P_r^{in,y}) \tag{6.34}$$

$$P_m^{in} = 1 - P_h^{in} - P_r^{in} \tag{6.35}$$

where P_h^{in}, P_m^{in} and P_r^{in} are the overall interconnected healthy, marginal and risk state probabilities respectively.

6.3 Determination of the Interruptible Load Carrying Capability

The analytical procedures developed to determine the ILCC in both isolated and interconnected generating systems are illustrated in this section. The first step in finding the ILCC of a given generation system is to find the firm load carrying capability. The operating criterion could be either a specified system risk, an acceptable healthy state probability or both. The specific healthy and risk state probabilities depend on the desired level of system security and are a management decision.

6.3.1 Determination of the Optimum Interruptible Load Carrying Capability in Isolated Systems

Consider that the number of committed units in System X is N_x for a system lead time of t_x. The generation model can be represented in the form of a Capacity Outage Probability Table (COPT) [3] consisting of simple arrays of l capacity levels (C) and the associated individual probabilities (p), i.e. probability of exactly the indicated amount of capacity being in service, and cumulative probabilities (P), i.e. probability of finding a quantity of capacity in service equal to or less than the indicated amount.

$$C = (C_1, C_2, \ldots, C_{i-1}, C_i, \ldots, C_l) \tag{6.36}$$

$$p = (p_1, p_2, \ldots, p_{i-1}, p_i, \ldots, p_l) \tag{6.37}$$

$$P = (P_1, P_2, \ldots, P_{i-1}, P_i, \ldots, P_l) \tag{6.38}$$

The initial value of the firm load carrying capability $FLCC_0$ can be found using the COPT and the specified risk.

$$P_i \leq P_{rs} < P_{i-1} \qquad \text{then} \qquad FLCC_0 = C_i \tag{6.39}$$

The actual *FLCC* is then found by starting from the initial value and using an iterative method. For the *ith* iteration:

$$\text{If } P_h \geq P_{hs} \text{ and } P_r \leq P_{rs} \qquad FLCC^i = FLCC^{i-1} + \Delta l \tag{6.40}$$

$$\text{If } P_h < P_{hs} \text{ or } P_r > P_{rs} \qquad FLCC^i = FLCC^{i-1} - \Delta l \tag{6.41}$$

Where P_{rs} and P_{hs} are the specified risk and healthy state probabilities respectively. Once the *FLCC* is determined, the system cannot carry additional load without committing more units. The operating criteria, however, may be satisfied without committing additional units if the added load is curtailed in a time less than the system lead time t_x. The algorithm described in Figure 6.2 is used to determine the interruption time τ.

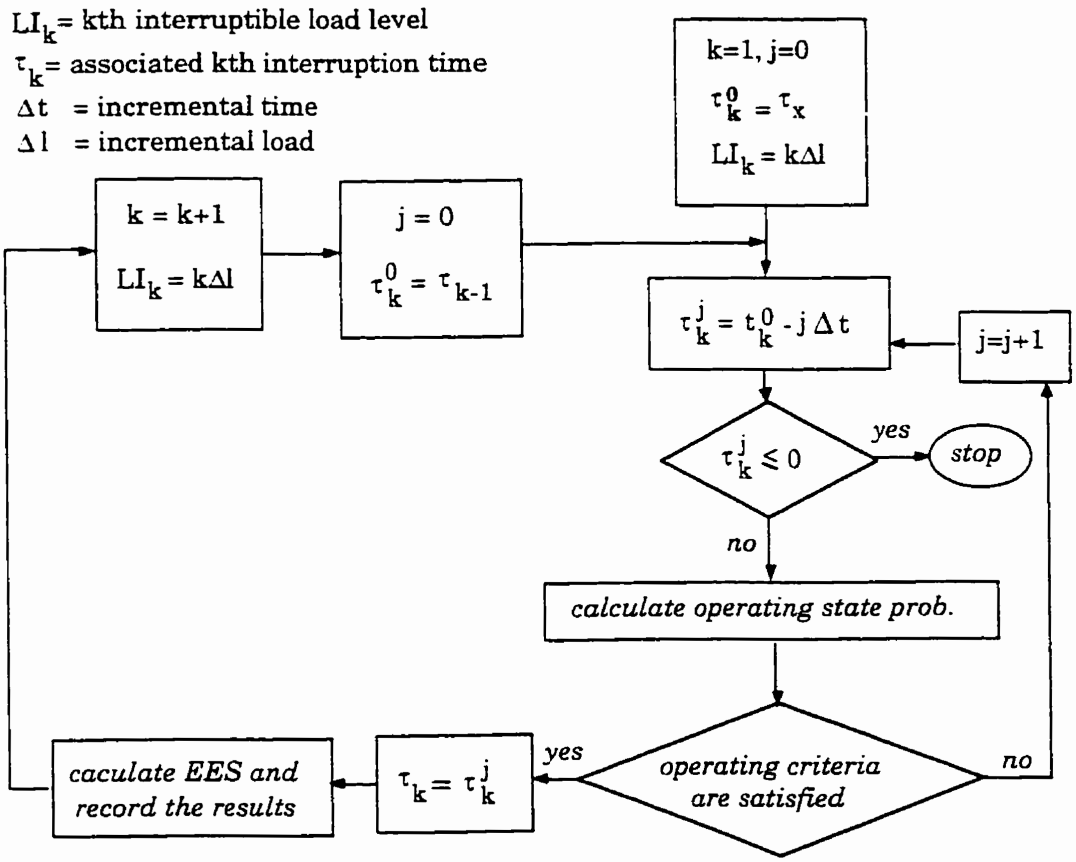

Figure 6.2: Algorithm for finding the ILCC and the interruption time.

The set of interruptible loads is determined using this procedure. An iterative method is then used to find the set of corresponding interruption times. The interruption time at each load level is used as the initial value for the next level. The operating state probabilities are within limits for all interruptible load levels in the set. After all the possible interruptible load levels and the associated lead times are determined, the next step is to find the optimum interruptible load level and the corresponding lead time. This is done by calculating the Expected Energy Supplied (EES) at each level. The EES associated with the *kth* level is determined as follows:

$$EES_k = \sum_{j_1=1}^{m_1}(FLCC + LI_k)\tau_k p_{j_1} + \sum_{j_2=m_1+1}^{l} C_{j_2}\tau_k p_{j_2} + \sum_{j_3=1}^{m_2} FLCC(t_x - \tau_k)p_{j_3} + \sum_{j_4=m_2+1}^{l} C_{j_4}(t_x - \tau_k)p_{j_4} \tag{6.42}$$

where

$m_1,\ m_2$	Integer values such that; $C_{m_1+1} \le FLCC + LI_k < C_{m_1}$ and $C_{m_2+1} \le FLCC < C_{m_2}$
$p_{j_1}, p_{j_2}, p_{j_3}, p_{j_4}$	Individual probabilities associated with C_{j1}, C_{j2}, C_{j3}, and C_{j4} in the COPT,
l	Number of generation capacity states in the COPT.
LI_k	*kth* interruptible load level.

The interruptible load level which has the maximum EES is designated as the Optimum Interruptible Load Carrying Capability (OILCC).

$$OILCC = \{ILCC_k \mid EES_k = Max(EES_i),\ i = 1,\ldots,K\} \tag{6.43}$$

6.3.2 Determination of the Optimum Interruptible Load Carrying Capability in Interconnected Systems

System well-being can be considerably improved by interconnection with other systems. When two systems are interconnected, both the isolated system operating criteria and the interconnected system criteria must be satisfied [129]. The isolated system operating criteria are illustrated in the previous section. The interconnected operating criterion could be a specified interconnected risk SP_r^{in}, an acceptable interconnected healthy state probability SP_h^{in}, or both as illustrated in the following.

$$P_r^{in} \le SP_r^{in}, \quad P_h^{in} \ge SP_h^{in} \tag{6.44}$$

Assume that $FLCC_x$ and $FLCC_y$ are the $FLCC$ of isolated systems X and Y respectively. Each system can satisfy the isolated operating criterion with a designated number of units and an associated $FLCC$. The number of committed units in systems X and Y are N_x and N_y respectively and remain the same for both the isolated and interconnected studies. The overall interconnected indices are then determined using the calculated isolated $FLCC$ as the initial values. The interconnected system operating criterion may or may not be satisfied at $FLCC_x$ and $FLCC_y$. If the interconnected operating criteria are not satisfied then the $FLCC$ levels are adjusted. An iterative method is used to find the individual system $FLCC$ at which the interconnected operating criterion is satisfied. Given $P_r^{in} > SP_r^{in}$ then:

$$\text{If} \quad P_r^{in,x} > P_r^{in,y} \quad \text{then} \quad FLCC_x = FLCC_x - \Delta l \tag{6.45}$$

$$\text{If} \quad P_r^{in,y} > P_r^{in,x} \quad \text{then} \quad FLCC_y = FLCC_y - \Delta l \tag{6.46}$$

The adjustments continue until $P_r^{in} \le SP_r^{in}$. The criterion of satisfying a specified interconnected healthy state probability is then checked, if required.

Given $P_h^{in} < SP_h^{in}$ then:

$$\text{If} \quad P_h^{in,x} < P_h^{in,y} \quad \text{then} \quad FLCC_x = FLCC_x - \Delta l \tag{6.47}$$

$$\text{If} \quad P_h^{in,y} < P_h^{in,x} \quad \text{then} \quad FLCC_y = FLCC_y - \Delta l \tag{6.48}$$

The final *FLCC* levels satisfy both the isolated and interconnected operating criteria.

A set of *ILCC* is then found for each isolated system at the modified *FLCC* using the procedure presented earlier. Consider $S_x(\theta_x, \tau_x)$ and $S_y(\theta_y, \tau_y)$ are the *ILCC* sets in systems X and Y where J and K are the number of *ILCC* levels in each set respectively. The isolated system operating criteria are satisfied at each level of S_x and S_y.

$$S_x(\theta_x, \tau_x) = \left\{(\theta_x^j, \tau_x^j) \middle| \, j = 1, \ldots, J\right\} \tag{6.49}$$

$$S_y(\theta_y, \tau_y) = \left\{(\theta_y^k, \tau_y^k) \middle| \, k = 1, \ldots, K\right\} \tag{6.50}$$

Where

θ_x^j, τ_x^j — *jth* *ILCC* level and the associated interruption time in System X respectively, and

θ_y^k, τ_y^k — *kth* *ILCC* level and the associated interruption time in System Y respectively.

It should be noted that the interruption time associated with each interruptible load level is the maximum allowable time in which the load must be curtailed, if required. Any time less than the calculated interruption time is therefore acceptable but results in a lower EES. The operating indices for two interconnected systems with interruptible loads can be found using the area risk curve concept. The evaluation technique is similar to that used for an isolated system. Using the two sets S_x and S_y, a new set S_{xy} is created and considered as the initial interconnected system *ILCC* set. This set consists of $J * K$ levels, defined as follows.

$$S_{xy}^{0}(\theta_x, \tau_x, \theta_y, \tau_y) = \left\{ (\theta_x^i, \tau_x^i, \theta_y^i, \tau_y^i) \mid i = 1, \ldots, J * K \right\} \tag{6.51}$$

where for the *ith* level, θ_x^i and θ_y^i are interruptible loads and τ_x^i and τ_y^i are the associated interruption times in systems X and Y respectively. The interconnected operating indices are calculated for each level and compared with the specified values. The interconnected system operating criterion may or may not be satisfied at the initial values. If the operating criterion is satisfied, the load condition is considered as an acceptable interconnected system *ILCC* level. If the operating criterion is not satisfied, the interruption time is iteratively modified by discrete time steps Δt to meet the criterion. The modification of τ_x^i and τ_y^i is done such that the incremental Expected Unsupplied Energy (ΔEUE) is minimized while satisfying the operating criterion. The ΔEUE is the difference between the total expected energy supplied (TEES) in two subsequent iterations.

$$\Delta EUE_1 = TEES(\tau_x, \tau_y) - TEES(\tau_x - \Delta t, \tau_y) \tag{6.52}$$

$$\Delta EUE_2 = TEES(\tau_x, \tau_y) - TEES(\tau_x, \tau_y - \Delta t) \tag{6.53}$$

$$\text{If} \quad \Delta EUE_1 < \Delta EUE_2 \qquad \text{then} \qquad \tau_x \rightarrow \tau_x - \Delta t \tag{6.54}$$

$$\text{If} \quad \Delta EUE_2 < \Delta EUE_1 \qquad \text{then} \qquad \tau_y \rightarrow \tau_y - \Delta t \tag{6.55}$$

The TEES for the *ith* level is given by:

$$TEES^i = EES_x^i + EES_y^i + \alpha_1^i EEA_{xy}^i + \alpha_2^i EEA_{yx}^i \tag{6.56}$$

Equation 6.56 consists of four terms. The first two terms are calculated using Equation 6.42, and are the EES in systems X and Y without considering the assistance from the other system. The last two terms (EEA_{xy}^i

and EEA^i_{yx}) are the expected energy assistance from one system to its neighbor calculated using Equation 6.57.

$$EEA^i_{xy} = \sum_{k=1}^{n1} C'_{xy}(k)p'_{xy}(k)\tau_x + \sum_{j=1}^{n2} C"_{xy}(j)p"_{xy}(j)(t_x - \tau_x) \tag{6.57}$$

where

$C'_{xy}(k)$, $p'_{xy}(k)$	*kth* capacity available state and its associated probability respectively in the tie constrained assistance model of System X to System Y for the period (0 to τ_x),
$C"_{xy}(j)$, $p"_{xy}(j)$	*jth* capacity available state and its associated probability respectively in the tie constrained assistance model of System X to System Y for the period (τ_x to t_x),
$n1$, $n2$	Number of capacity states in the tie constrained assistance models for the period (0 to τ_x) and (τ_x to t_x) respectively, and
α^i_1, α^i_2	Weighting factors.

$$\alpha^i_1 = \frac{EES^i_x}{EES^i_x + EES^i_y} \tag{6.58}$$

$$\alpha^i_2 = \frac{EES^i_y}{EES^i_x + EES^i_y} \tag{6.59}$$

The EEA^i_{yx} is calculated in a similar manner to EEA^i_{xy}. The tie constrained assistance model utilized in Equation (6.57) is an equivalent multi-state generating unit [20]. The tie constrained assistance models for the two periods (0 to τ_x) and (τ_x to t_x) are different due to the different load levels in System X for the two periods. The two weighting factors α_1 and α_2 modify the assistance from one system to another based on their sizes and the available capacities.

This procedure is continued until the interconnected system operating criterion is satisfied. The amount of interruptible load for some of the levels in S^{0}_{xy} is such that the interconnected system operating criterion cannot be satisfied even after adjusting the interruption time . In these cases the levels are ignored. The total expected energy supplied (TEES) is calculated for those ILCC levels for which the operating criterion is satisfied within the system lead time.

The total number of ILCC levels in the interconnected systems in which the interconnected system operating criterion is satisfied will be less than or equal to $J * K$. The level which has the maximum TEES is considered as the OILCC for the interconnected systems.

6.4 Application to the IEEE Reliability Test System

The concepts presented in the previous sections have been applied to the IEEE-RTS. The generating unit data and the priority loading order for the IEEE-RTS are shown in Table 2.1.

6.4.1 Interruptible Load Carrying Capability in Isolated Systems

Consider a system lead time of 4 hours and a specified risk of 0.01 as the operating criterion. The firm load carrying capabilities (FLCC) associated with 8, 13 and 18 committed units in the priority loading order are shown in Table 6.1, together with the corresponding system health, margin and risk probabilities. The healthy state probabilities are zero as the system cannot tolerate single unit outages with the number of committed units and at the corresponding FLCC. The FLCC for 8, 13 and 18 committed units decreases to 1147, 2006 and 2537 respectively if the system is required to satisfy a healthy state probability of 0.9 in addition to a specified risk of 0.01.

Table 6.1: FLCC and the associated well-being indices.

No. of units	FLCC MW	Probability of Health	Margin	Risk
8	1195	0	0.99268145	0.00731855
13	2055	0	0.99240188	0.00759812
18	2585	0	0.99229345	0.00770655

The set of ILCC calculated for each FLCC at the corresponding number of committed units is shown in Figure 6.3, and ranges from 0 to 350 MW. Each ILCC has an associated interruption time. For example, the system with 18 committed units and at the FLCC of 2585 MW, can carry an additional interruptible load of 200 MW with an interruption time of 16 minutes.

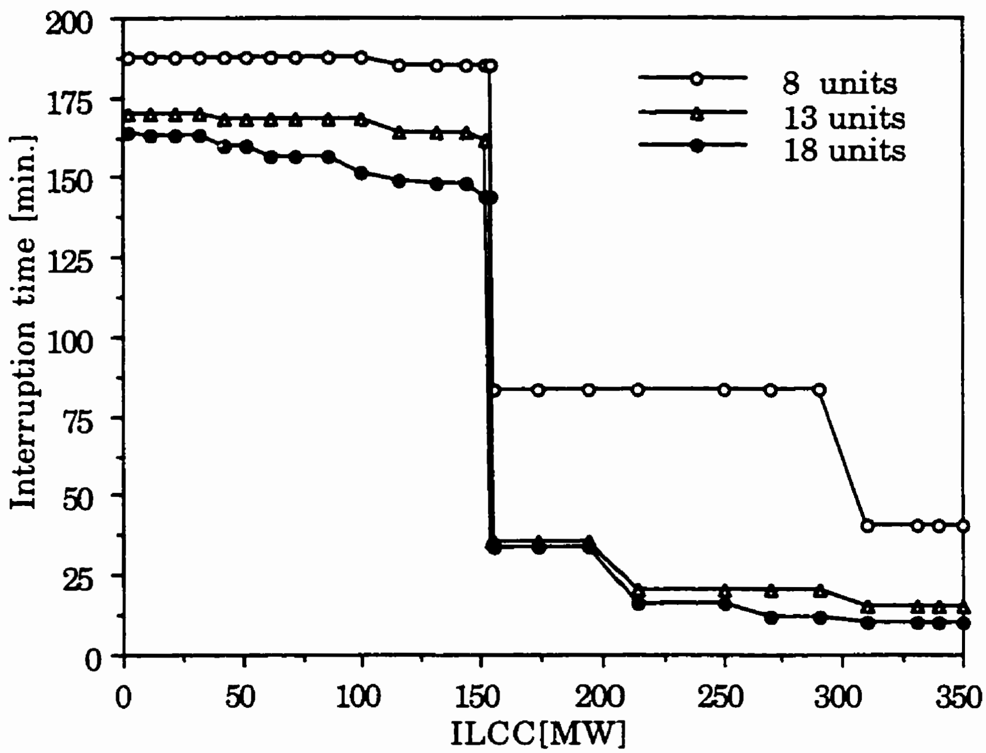

Figure 6.3: Variation of interruption time versus ILCC.

The EES associated with each ILCC is shown in Figure 6.4. The optimum ILCC is the one for which the system has the highest EES. The OILCC and the associated interruption times (IT) for the three cases are shown in Table 6.2. Figures 6.5 and 6.6 show the FLCC, optimum ILCC, interruption time and the corresponding EES for the IEEE-RTS when the number of committed units varies from 8 to 32. It can be seen that for this system, the OILCC is constant for a range of committed units. The associated interruption times, however, vary from 124 to 185 minutes.

Table 6.2: Optimum ILCC and the associated interruption time.

No. of units	OILCC MW	IT min.	Probability of Health	Probability of Margin	Probability of Risk
8	154	185	0.00000846	0.99000384	0.00998770
13	152	161	0.00001352	0.98999803	0.00998845
18	154	144	0.00002006	0.98999436	0.00998558

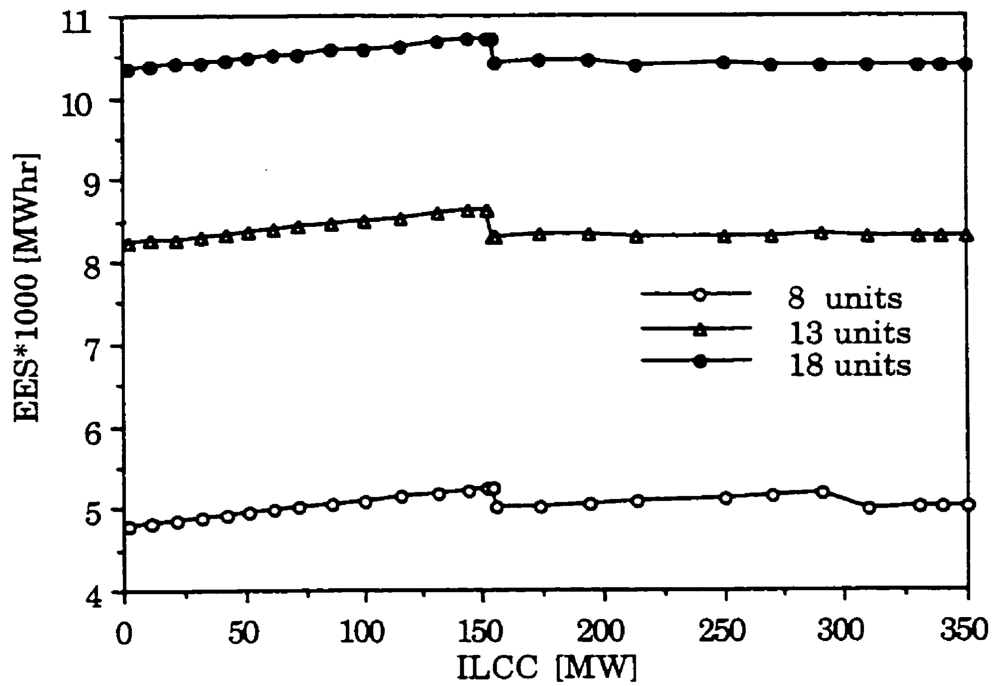

Figure 6.4: Variation of expected energy supplied (EES) versus ILCC.

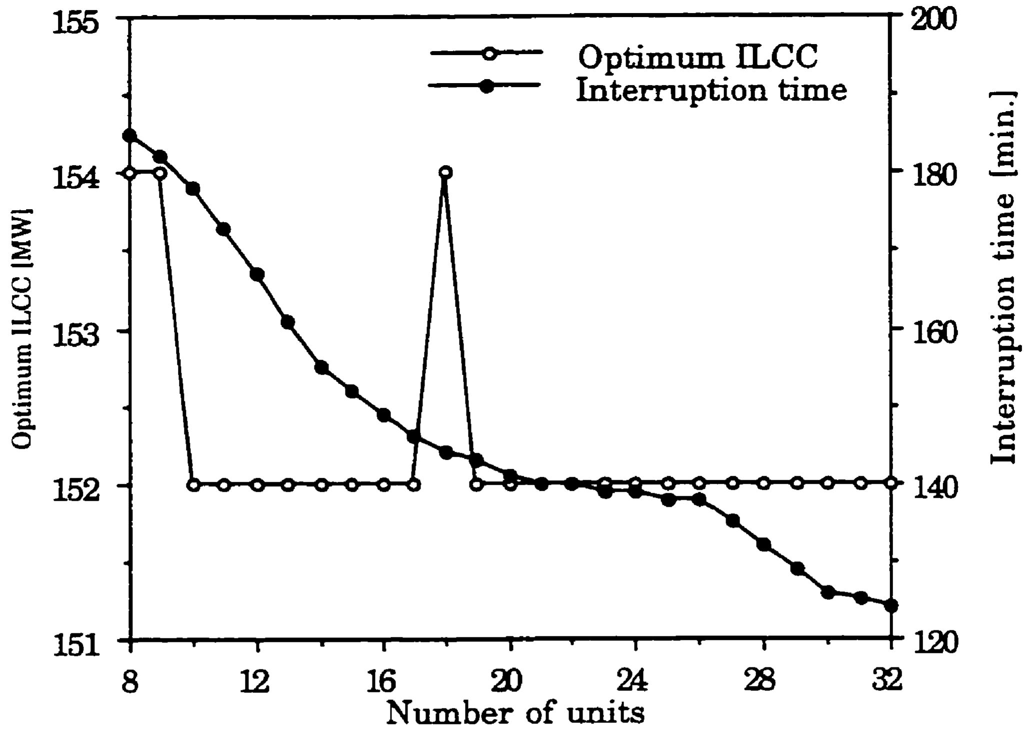

Figure 6.5: Variation of OILCC and interruption time versus number of committed units.

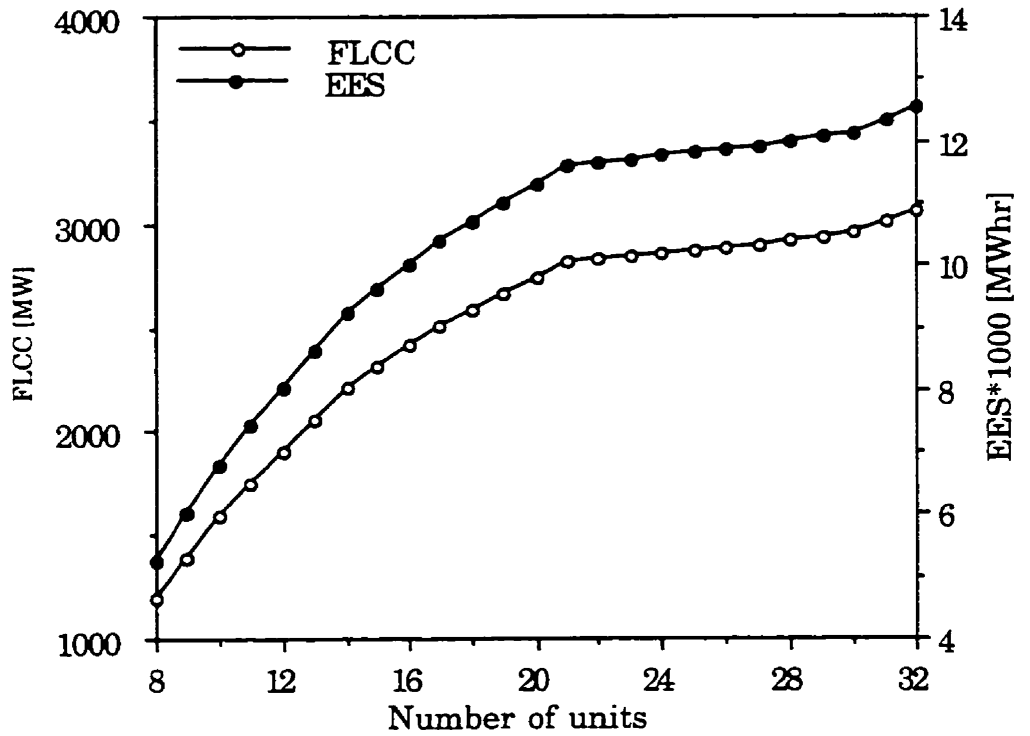

Figure 6.6: Variation of FLCC and EES versus number of committed units.

6.4.2 Interruptible Load Carrying Capability in Interconnected Systems

In order to illustrate the effect of interconnection, two IEEE-RTS, designated as 1 and 2, are interconnected by two tie lines each capable of transferring 100 MW. Each tie line has a failure rate of one failure per year. Each system has a lead time of 4 hours, and should satisfy a single system risk of 0.01. In addition, the interconnected system operating criterion is an interconnected system risk of 0.001 and a healthy state probability of 0.9. Table 6.3 shows the results when the number of committed units in IEEE-RTS1 are 8, 13 and 18. The number of committed units in IEEE-RTS2 is fixed at 8. Each system satisfies both the isolated and interconnected system operating criteria at the corresponding FLCC. The OILCC associated with the two systems are determined from the ILCC sets of each system. Comparing Table 6.3 with the results shown in Table 6.2, it can be seen that the OILCC are not the same for the two cases.

Table 6.3: Optimum ILCC and the associated interruption times.

No. of units		FLCC [MW]		OILCC [MW]		IT [min.]		Overall interconnected system		
1	2	1	2	1	2	1	2	Health	Margin	Risk
8	8	1195	1195	150	150	185	185	0.9540006	0.0457207	0.0002787
13	8	2055	1195	150	150	161	185	0.9342116	0.0653514	0.0004370
18	8	2585	1195	150	150	145	185	0.9192283	0.0802718	0.0004999

Figure 6.7 shows the variation in the TEES versus the *ILCCs* in the two systems. The numbers of committed units in the two systems are 13 and 8. The point showing the highest TEES in Figure 6.7 is considered as the OILCC. The associated interruption times are not shown in the figure but are presented in Table 6.3. Figure 6.8 shows the variation in the OILCC for

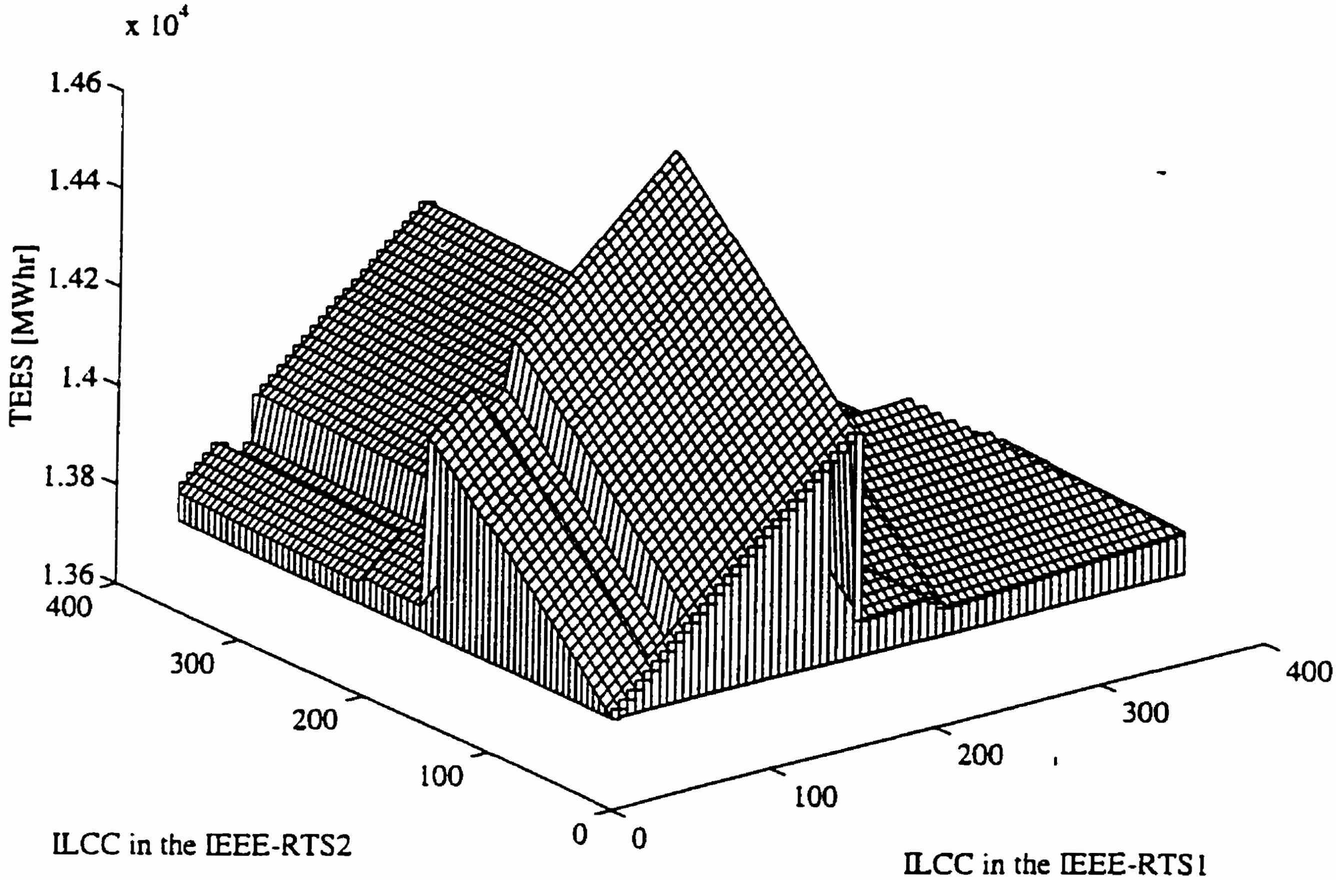

Figure 6.7: Variation of the TEES versus ILCC in Systems 1 and 2.

IEEE-RTS1 when interconnected to IEEE-RTS2. The number of committed units in System 1 varies from 8 to 32 while in the second system it is fixed at 8. The OILCC of IEEE-RTS2 is 150 MW and the associated interruption time is 185 minutes for all cases. The OILCC in IEEE-RTS1 varies from 150 MW

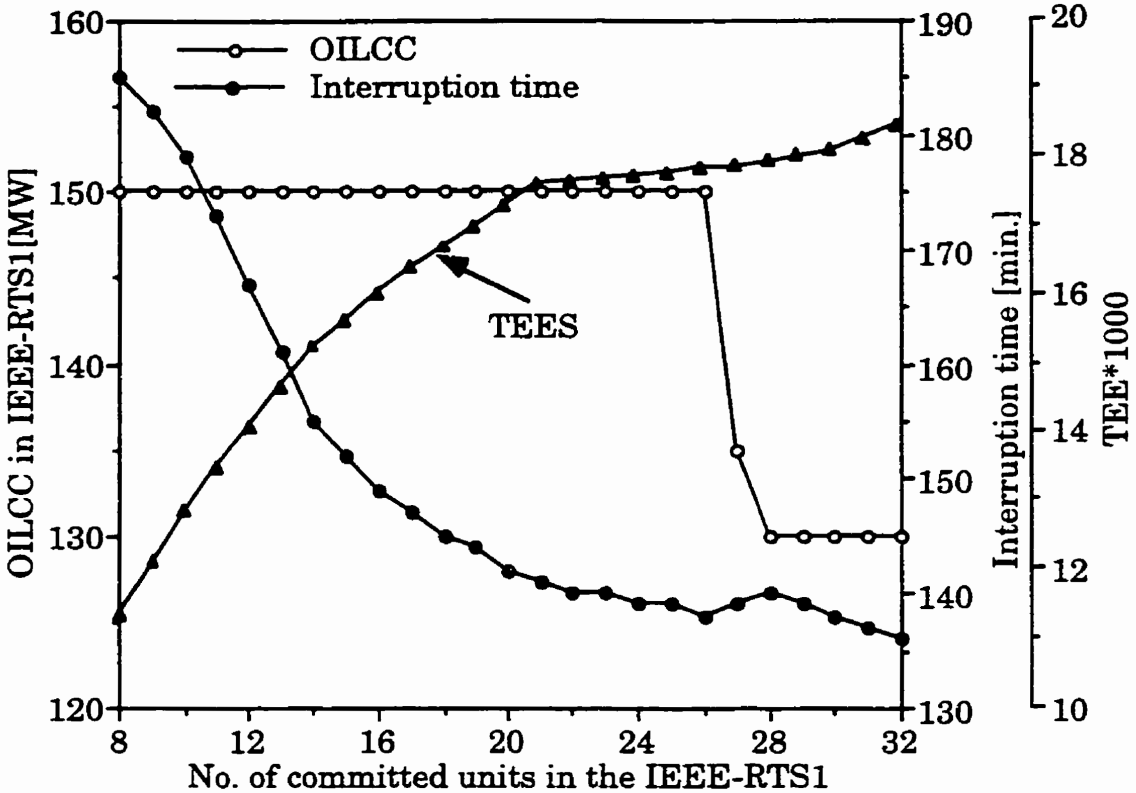

Figure 6.8: Variation of OILCC and TEES.

to 130 MW. The corresponding interruption time varies from 185 to 136 minutes. It is important to note that the OILCC and the associated interruption time depends on the FLCC of the two systems, the tie line carrying capability and the system operating criteria. Table 6.4 shows the OILCC and the corresponding interruption times for the two interconnected IEEE-RTS. Each system should satisfy an isolated risk of 0.01 and an interconnected risk of 0.001. In addition, an acceptable healthy state probability of 0.9 must be satisfied in the interconnected mode. Each system has a lead time of 4 hours. System B has a load level of 1195 MW with 8 units. The number of committed units in System A varies from 8 to 32 units. Table 6.4 is an extension of the concepts described in Figure 6.7. Table 6.4 shows the OILCC for a range of peak loads in System A.

Table 6.4: OILCC and the corresponding interruption time of two interconnected IEEE-RTS.

LA	NA	LB	NB	LIA	LIB	TIA	TIB	LT	PH	PM	PR	TEES
1195	8	1195	8	150	150	185	185	240	0.95400059	0.04572067	0.00027874	11264.51
1392	9	1195	8	150	150	182	185	240	0.94998225	0.04970371	0.00031404	12044.09
1590	10	1195	8	150	150	185	185	240	0.95498268	0.05366950	0.00034782	12825.12
1745	11	1195	8	150	150	185	185	240	0.94204082	0.05758006	0.00037912	13432.17
1900	12	1195	8	150	150	167	185	240	0.93811756	0.06147405	0.00040839	14036.85
2055	13	1195	8	150	150	161	185	240	0.93421158	0.06535140	0.00043702	14641.59
2210	14	1195	8	150	150	155	185	240	0.93032283	0.06921213	0.00046505	15246.39
2310	15	1195	8	150	150	152	185	240	0.92723727	0.07228720	0.00047553	15638.79
2410	16	1195	8	150	150	149	185	240	0.92416277	0.07535223	0.00048500	16031.22
2510	17	1195	8	150	150	147	185	240	0.92109745	0.07840708	0.00049547	16426.00
2585	18	1195	8	150	150	145	185	240	0.91922825	0.08027182	0.00049993	16721.18
2662	19	1195	8	150	150	144	185	240	0.91736119	0.08213266	0.00050615	17026.50
2738	20	1195	8	150	150	142	185	240	0.91550009	0.08398995	0.00050997	17325.53
2814	21	1195	8	150	150	141	185	240	0.91364094	0.08584333	0.00051573	17626.96
2826	22	1195	8	150	150	140	185	240	0.91240199	0.08708119	0.00051682	17672.56
2838	23	1195	8	150	150	140	185	240	0.91116261	0.08831718	0.00052021	17720.54
2850	24	1195	8	150	150	139	185	240	0.90992711	0.08955171	0.00052117	17766.14
2862	25	1195	8	150	150	139	185	240	0.90869113	0.9078437	0.00052450	17814.12
2874	26	1195	8	150	150	138	185	240	0.90745907	0.09201559	0.00052534	17859.72
2894	27	1195	8	135	150	139	185	240	0.90551597	0.09395154	0.00053248	17908.30
2914	28	1195	8	130	150	140	185	240	0.91344066	0.08604478	0.00051456	17979.20
2934	29	1195	8	130	150	139	185	240	0.91324609	0.08624073	0.00051318	18057.05
2954	30	1195	8	130	150	138	185	240	0.91298282	0.08650526	0.00051192	18134.97
3004	31	1195	8	130	150	137	185	240	0.91112475	0.08836059	0.00051466	18332.82
3054	32	1195	8	130	150	136	185	240	0.90927056	0.09021217	0.00051727	18530.70

LA =Peak load in System A
LB =Peak load in System B
LT =Systems lead time
PH =Healthy state probability
PM =Marginal state probability
PR =Risk state probability
TEES =Total expected energy supplied [MWhr]
LIA, LIB =OILCC in Systems A and B respectively,
NA, NB =Number of committed units in Systems A and B respectively,
TIA, TIB =Corresponding time interruptions in Systems A and B respectively,

6.5 Conclusions

A probabilistic technique is presented in this chapter to evaluate the Optimum Interruptible Load Carrying Capability (OILCC) in both isolated and interconnected generating systems. A generating system with a given number of committed units can serve a target firm load designated as the FLCC. A set of ILCC can be determined for this number of committed units and the associated FLCC, which contains the interruptible load levels and the corresponding interruption times. The ILCC level which maximizes the expected energy supplied is taken from the set and designated as the OILCC of the generation system.

The OILCC for two interconnected systems is determined by combining the two sets associated with the isolated systems. The interruption times are modified using an energy based approach to satisfy the interconnected system operating criteria. The technique is illustrated by application to the IEEE-RTS and results are presented and discussed for both isolated and interconnected system studies.

Conventional HLI unit commitment health analysis does not normally include transmission facilities and the actual location of the generating units. The approach illustrated in the next two chapters is a new technique for operating reserve evaluation, which includes the ability of the transmission system to deliver the generated energy to the major load points. This approach provides a more realistic appraisal of system well-being indices than a basic HLI evaluation.

7. BASIC CONCEPTS OF UNIT COMMITMENT HEALTH ANALYSIS IN COMPOSITE SYSTEMS

7.1 Introduction

One of the most basic elements in power system operation is the determination of how much generating capacity should be committed to meet the system load while satisfying the operating criteria. This capacity should contain sufficient reserve to supply the system requirements under conditions of generating unit forced outages or unforeseen variations in the system load. These aspects were covered in the previous chapters at HLI. A second but equally important element in the operating process is to assess the ability of the transmission system to transfer the generated energy to the major load points. Complete analysis of this problem involves a detailed treatment on an integrated basis of both the generation and transmission facilities [142].

The techniques presented in the previous chapters are focused on the generating system functional zone designated as HLI. Operating health analysis at HLI is based on the concept that the committed units can be considered to be connected to a system bus and serve the total system load demand at this bus. Transmission constraints and the actual physical location of the generating units are not included in the analysis. In an actual power system, the generating units and loads are usually dispersed throughout the system and are not concentrated at a single bus. In hierarchical level II (HLII) studies, the simple generation/load model used in

HLI is extended to include bulk transmission facilities. Reliability analysis at this level is usually termed as composite system reliability evaluation. Operating reserve assessment, therefore, should include not only the generation capacity in the system and the total load demand, but also the associated transmission network. In a practical power system, the reliability associated with a transmission network depends on many factors and can create a wide range of operational restrictions.

The concepts of HLI unit commitment health analysis is extended in this chapter to unit commitment in composite generation and transmission systems. The problem of unit commitment is decomposed into two subproblems. Generating units are first committed to the system based on HLI operating criteria [60] followed by unit commitment evaluation at HLII. The committed capacity should satisfy the operating criteria at both HLI and HLII. Operating reserve evaluation at HLII recognizes the ability of the transmission system to deliver the generated energy to the major load points and therefore contains additional constraints such as acceptable voltages at load buses, transmission line load carrying capabilities and real and reactive power considerations. A procedure is introduced to determine the operating state probabilities using a contingency enumeration technique. The required number of committed units and the associated well-being indices at HLI and HLII are determined for a given load level. The results are compared and discussed by application to the IEEE-RTS.

7.2 Network Solution Techniques

Operating reserve assessment of a bulk power system generally involves the solution of the network configuration under selected outage situations.

Various techniques, depending upon the adequacy and security criteria and the intent behind these studies are available for analyzing the system. The three basic analytical approaches utilized in power system analysis are the network flow, dc load flow and ac load flow techniques. The selection of an appropriate technique is of prime importance and is an engineering decision. The selected technique, however, should be capable of satisfying the intent behind the studies from a management, planning and operating point of view [67].

It is not realistic to attempt to consider all possible contingencies in an operating reserve evaluation study. The main constraint in considering a large number of outage events is the computation time required to solve these contingencies using an acceptable solution technique. This may dictate fast solution techniques using simplified or approximate methods. One of the simplest approaches is to treat the system as a transportation model [143,144] and to examine it in terms of its ability to ensure the continuity of power supply at various load centers. This technique, when applied to composite power system reliability evaluation, is basically concerned with the continuity of the power flow from the generating buses to the major load points in order to supply the load demand in the system. The constraints are the generating capacity available at the generating buses and the power carrying capabilities of the transmission lines.

The approximate dc load flow technique [145] applied in contingency analysis can be formulated as the following linear model:

$$[P]=[B][\delta] \tag{7.1}$$

where

$[P]$ Vector of bus power injection,

$[B]$ System susceptance matrix and,
$[\delta]$ Vector of bus phase angle.

The vector of bus phase angle $[\delta]$ can be obtained by solving Equation 7.1 using $[P]$ and $[B]$. Optimal ordering and triangular factorization of the system susceptance matrix are used to achieve rapid solution time. The bus phase angles, computed using forward and backward substitution, are then used to determine the individual branch flows as given by:

$$P_{ij} = \frac{\delta_i - \delta_j}{X_{ij}} \tag{7.2}$$

where

P_{ij} Real power flow from Bus i to Bus j,
δ_i Phase angle at Bus i,
δ_j Phase angle at Bus j and,
X_{ij} Reactance of the line between Bus i and Bus j.

It can be seen from Equation 7.2 that for a fixed set of power injection $[P]$, if a line(s) is(are) removed from system then both $[B]$ and $[\delta]$ will change from their base case values. The changes in angle vector can be computed using the Sherman-Morrison correction formula [146] instead of rebuilding and factorizing the system susceptance matrix $[B]$. The new line flows can be calculated from Equation 7.2 using the new values of $[\delta]_{new}$.

Approximate load flow techniques such as dc load flow method are relatively simple and fast but do not provide any estimate of the bus voltage and the reactive power requirements of the generating units. The fast decoupled load flow technique is a good compromise between ac and dc load flow approaches in regard to storage requirements and solution speed. It can also be used to check the voltage quality of a power system thus meeting the two important adequacy requirements. A brief description of the fast decoupled load flow technique is given below.

The general equations for the power mismatch at all system buses except the swing bus can be obtained using the Newton-Raphson method [147]. The fast decoupled load flow approach neglects the weak coupling between the changes in real power and voltage magnitude, and the changes in reactive power and phase angle. The mismatches of active and reactive power can therefore be expressed by Equations 7.3 and 7.4.

$$[\Delta P] = [J_\delta][\Delta\delta], \tag{7.3}$$

$$[\Delta Q] = [J_v][\Delta V / V] \tag{7.4}$$

where

ΔP_i	Active power mismatch at Bus i,
ΔQ_i	Reactive power mismatch at Bus i,
$\Delta\delta_i$	Increment in phase angle of the voltage at Bus i,
ΔV_i	Increment in magnitude of the voltage at Bus i,
J_δ, J_v	Submatrixes of the Jacobian matrix,
δ_i	Phase angle of the voltage at Bus i and,
V_i	Magnitude of the voltage at Bus i.

Equations 7.3 and 7.4 can be further simplified by making the following assumptions, which are usually valid in a practical power system:

$cos(\delta_i - \delta_j) \cong 1.0$,

$g_{ij}.sin(\delta_i - \delta_j) << b_{ij}$ and

$Q_i << b_{ij}.V_i^2$,

where

$g_{ij} - jb_{ij}$	Series admittance of the line connecting Buses i and j and
Q_i	Reactive power at Bus i.

Considering the above assumptions Equations 7.5 and 7.6 are derived from Equations 7.3 and 7.4.

$$[\Delta P]=[V.B'.V][\Delta\delta] \tag{7.5}$$

$$[\Delta Q]=[V.B''.V][\Delta V/V] \tag{7.6}$$

The final equations used in the fast decoupled load flow technique are given in Equations 7.7 and 7.8 after making further physically justifiable simplifications.

$$[\Delta P/V]=[B'][\Delta\delta] \tag{7.7}$$

$$[\Delta Q/V]=[B''][\Delta V] \tag{7.8}$$

Both matrixes $[B']$ and $[B'']$ are real, sparse and contain only network admittances. Since $[B']$ and $[B'']$ are constant, they need to be inverted or factorized only once at the beginning of the iterative process. The magnitude of the voltage at each load bus and the phase angle at each bus except the slack bus are modified as given in equations 7.9 and 7.10.

$$[\delta]_{new}=[\delta]_{old}+[\Delta\delta] \tag{7.9}$$

$$[V]_{new}=[V]_{old}+[\Delta V] \tag{7.10}$$

Power mismatch $[\Delta P]$ and $[\Delta Q]$ are calculated for these new values of bus angle and bus voltage. Equations 7.7 and 7.8 are iterated in some defined manner towards an exact solution, i.e. when power mismatches are less than the tolerance. In the case of line or transformer outages, the Sherman-Morrison correction technique [146] can be used to reflect the outages instead of rebuilding and refactorizing the system matrixes $[B']$ and $[B'']$.

7.3 Hierarchical Levels One and Two Security Constraints

The operating limits which have to be satisfied during the operation of a power system are designated as security constraints. There are many constraints that govern power system operation. The constraints applied in a given situation usually depend on the purpose behind the study. In an HLI operating reserve assessment, the basic system model is one in which the committed units and loads are connected to a single bus. The applied security constraints, therefore, refer to the power generated and the total load demand [60,61] as expressed in Equation 7.11 where P_k^{min} and P_k^{max} represent the minimum and the maximum power generation at Bus k. The corresponding region is defined by R_p.

$$R_p = \left\{P : P_k^{min} \le P_k \le P_k^{max}\right\} \qquad (7.11)$$

The effect of transmission lines and the actual physical location of the generating units are not considered in an HLI operating reserve assessment. Assessment of unit commitment at HLII, therefore, includes the ability of the transmission system to deliver the generated energy to the major load points. The basic HLII security constraints for acceptable power system operation can be considered as:

7.3.1 Line Flow Constraints

Thermal operating limits of the transmission lines and transformers dictate that the current flow through them should be limited. This can be expressed as:

$$R_\delta = \left\{\delta : \left|\delta_i - \delta_j\right| \le \theta_k\right\} \qquad (7.12)$$

Where k is the branch connecting Buses i and j and the associated region is defined as R_δ.

7.3.2 Voltage Magnitude Constraints

The voltage magnitude at all PQ buses should be within specified limits which can be expressed by region R_v.

$$R_v = \{V | V_{min.} \leq V \leq V_{max.}\} \tag{7.13}$$

Where $V_{min.}$ and $V_{max.}$ are minimum and maximum acceptable voltage levels respectively.

Operating reserve assessment at HLII can be performed considering one or a combination of the above constraints. The required number of committed units and the associated well-being indices are very dependent on the selected security constraint sets. In the results presented in this chapter, the security constraint sets are defined by combining R_p and R_δ or combining all the three constraints.

$$S_I = R_p \cap R_\delta \tag{7.14}$$

$$S_{II} = R_p \cap R_\delta \cap R_v \tag{7.15}$$

7.4 Model Implementation

The system well-being framework introduced in Chapter 2 can be used for unit commitment in a composite generation and transmission system. The state definitions, therefore, should consider the security constraints associated with a composite system. In the healthy state, all the equipment and security constraints are within limits while supplying the total system demand. In this state, there is sufficient margin such that the loss of any element in the system covered by the deterministic criteria, e.g. the loss of any single element, will not result in a limit being violated. The marginal state is similar to that of the healthy state, but there is no longer sufficient margin in the system such that the loss of some elements will result in a limit being violated. In the risk state, equipment or system constraints are violated and some load may be curtailed. It should be noted that in an HLI operating health analysis, the system elements are the committed generating units. The system, therefore, in the healthy state can tolerate the outage of any single generating unit [60]. In an HLII operating health analysis, the outage of any single committed unit, or any single transmission line should be tolerated in the healthy state. A risk index designated as the Generating System Operating State Risk (GSOSR), which is the probability of the system being in the risk state, was utilized in HLI unit commitment assessment [60]. A comparable index defined as the Composite System Operating State Risk (CSOSR) in the assessment of unit commitment at HLII. The probabilities associated with the healthy and risk states can be considered as unit commitment criteria.

7.5 Analysis Technique

The problem of composite system unit commitment is decomposed into two subproblems. For a given load level, unit scheduling is first performed at HLI in accordance with the specified HLI operating criteria. The basic objective is to satisfy Equation 7.16 [60,61].

$$P_r^{HLI} \le SP_r^{HLI} \tag{7.16}$$

If the system is required to satisfy multiple criteria at HLI, then Equation 7.17 must be satisfied in addition to Equation 7.16.

$$P_h^{HLI} \geq SP_h^{HLI} \tag{7.17}$$

where P_r^{HLI}, P_h^{HLI} and SP_r^{HLI} and SP_h^{HLI} are the HLI calculated and specified system risk and healthy state probabilities respectively.

Once the required number of committed units at HLI is determined, the well-being indices at HLII are calculated for the same number of committed units and load level. Even if the number of committed units is such that the system is operating in the healthy state at HLI, it may not be in the healthy state in HLII, depending on the security constraints considered. The system is therefore required to satisfy the HLII unit commitment criterion as expressed by Equation 7.18. For multiple criteria, Equation 7.19 must be satisfied in addition to Equation 7.18.

$$P_r^{HLII} \leq SP_r^{HLII} \tag{7.18}$$

$$P_h^{HLII} \geq SP_h^{HLII} \tag{7.19}$$

where P_r^{HLII}, P_h^{HLII} and SP_r^{HLII} and SP_h^{HLII} are the HLII calculated and specified system risk and healthy state probabilities respectively.

The operating state probabilities are calculated using a contingency enumeration technique which consists of three basic steps:

1. *Systematic selection and evaluation of contingencies,*
2. *Contingency classification according to predetermined security constraints,*
3. *Identifying the status of each contingency based on the operating state definitions.*

The number of cases that have to be evaluated in a composite system risk assessment can be very large. In the studies described in this chapter, therefore, the contingency classification was carried out using the selection technique [148] in order to reduce the computation time.

Figure 7.1 shows the flowchart for detecting the operating states up to third level outages. The flowchart can be extended to consider higher level outages. In this figure, FLV, SLV and TLV are used to recognize whether respectively First, Second or Third Level outages create a system problem or not. Having a value of 1 for FLV, SLV or TLV implies that the associated outage level created a system problem. A value of 0, however, is given to FLV, SLV or TLV, if no security constraint is violated due to single, second or third level outages respectively. The base case probability is calculated considering that all the committed units and transmission facilities are in service. The total probability of the enumerated contingencies is less than unity and the probabilities not captured in the enumeration approach are considered as part of the system risk. The system risk is, therefore, calculated using the complementary value of the summation of the healthy and marginal state probabilities. In the studies presented in this chapter, contingencies up to fourth-level generator outages, third level transmission lines outages and third level combined transmission and generating units outages are considered. If the security constraints are violated due to a given contingency, the system condition belongs to the risk state, otherwise it lies in either the healthy or marginal state depending on the impact of the next level outages of this system condition. Operating state designation decisions cannot be made for the highest outage order level (here third-level outages for transmission lines and fourth-level outages for the generating units) which do not violate the security constraint(s) due to not considering the next level. In this thesis, contingencies with these extreme conditions are considered to be in the marginal state. The obtained results are therefore slightly pessimistic.

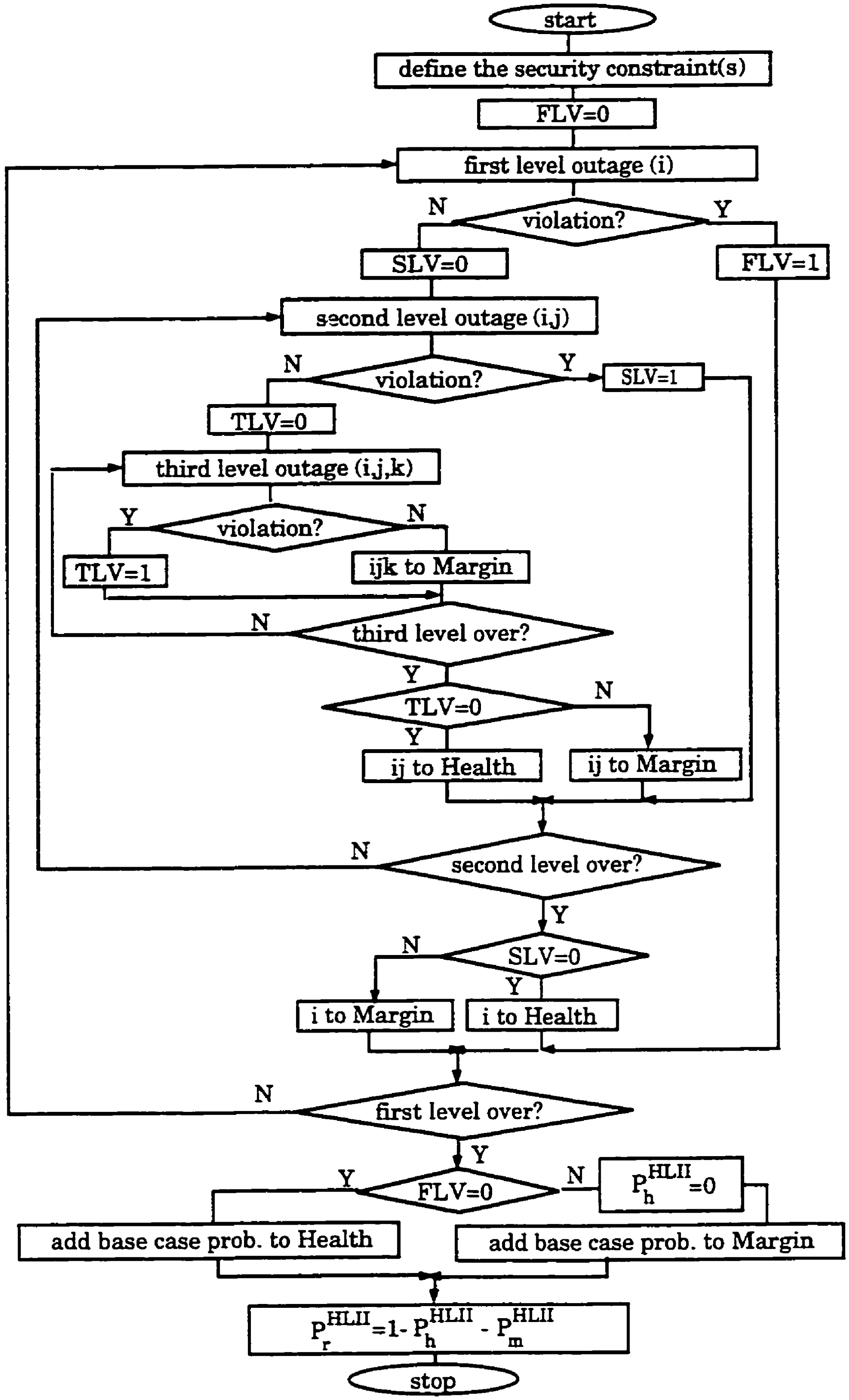

Figure 7.1 Flowchart for detecting operating state conditions.

7.6 Application to the IEEE Reliability Test System

Unit commitment health analyses using the IEEE-RTS are described in this chapter. The single line diagram of this system is shown in Figure 2.3. The system has 11 generator (PV) buses, 13 load (PQ) buses, 33 transmission lines and 5 transformers. The acceptable voltage limits for the system buses are assumed to be 1.05 and 0.95 p.u.. Failure rates, repair times and other load flow data can be found in Appendix C. From the single line diagram, it can be seen that the outage of Line 11 will isolate Bus 7. This isolation will cause the probability of the healthy state to be zero even though there is no other system violations. To avoid this situation, the first level outage of Line 11 and the associated higher level outages with this line are ignored. The number of generating units to be committed for a particular load level are taken from the priority order list given in Table 2.1.

Generating units are first committed to the system such that the HLI unit commitment criterion are satisfied [60]. The unit commitment criterion could be a specified risk, an acceptable healthy state probability or both depending on the required degree of reliability. The selection of specified values for the risk and the healthy state probabilities depends largely on the experience of the system operator and the conditions under which the system is being operated.

It should be noted that in a totally deregulated industry environment, there is no single body who can dictate the unit commitment that provides the least cost solution. Generator companies provide MW block price lists and the control operator, responsible for system security and reliability, commits blocks of energy from the published MW-price order list that satisfies the minimum spot price and system security. The idea of committing units from a

MW-price list is more or less equivalent to committing units from a priority order list. In this thesis, therefore, it is assumed that the merit order list is the MW-price order list and units are committed until the reliability condition(s) are satisfied.

7.6.1 Hierarchical Level One Unit Commitment Results

Figure 7.2 shows a typical hourly peak load variation in a 24 hour committed period in percent of the annual peak load for the IEEE-RTS . The annual peak load of the system is 2850 MW and the system lead time is assumed to be 4 hours. The required number of committed units at each hour is shown in Figure 7.3 for two different cases. In the single criterion (SC) case, a specified risk of 0.01 must be satisfied. The system is required to satisfy an acceptable healthy state probability of 0.9 in addition to a specified risk of 0.01 in the multiple criteria (MC) case. The system health and risk state probabilities associated with the two cases are shown in Figures 7.4 and 7.5, where the healthy state probability is zero for the SC case during the 24 hour period. This is due to insufficient spinning reserve to tolerate single unit outages. The system, therefore, must commit more unit(s) in addition to those already committed to satisfy the multiple criteria.

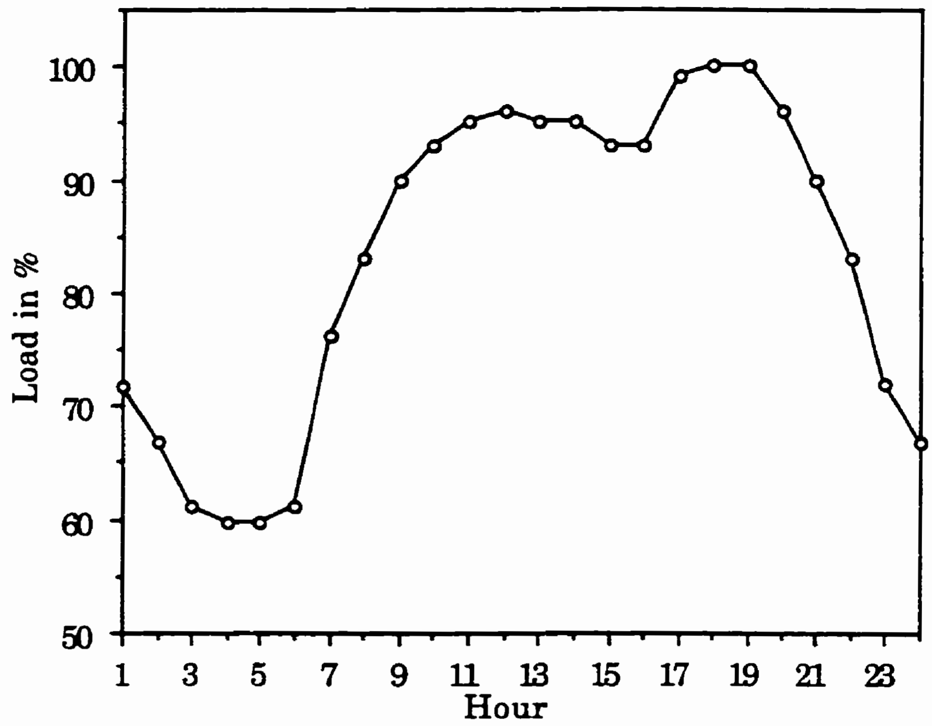

Figure 7.2: 24 hour load variation for the IEEE-RTS.

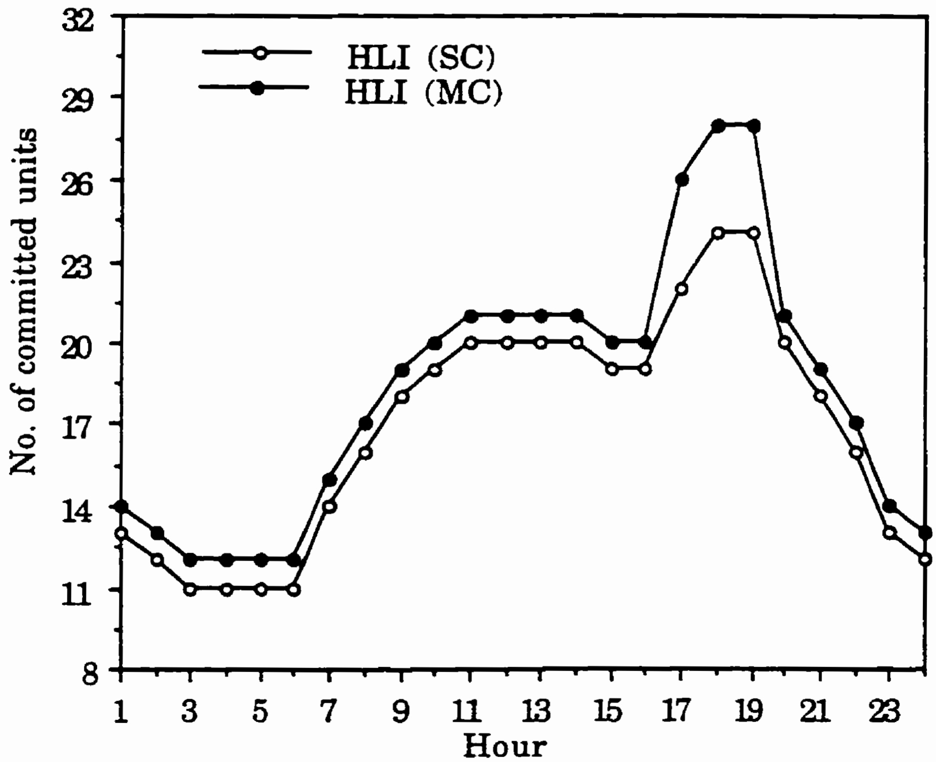

Figure 7.3: Required number of committed units.

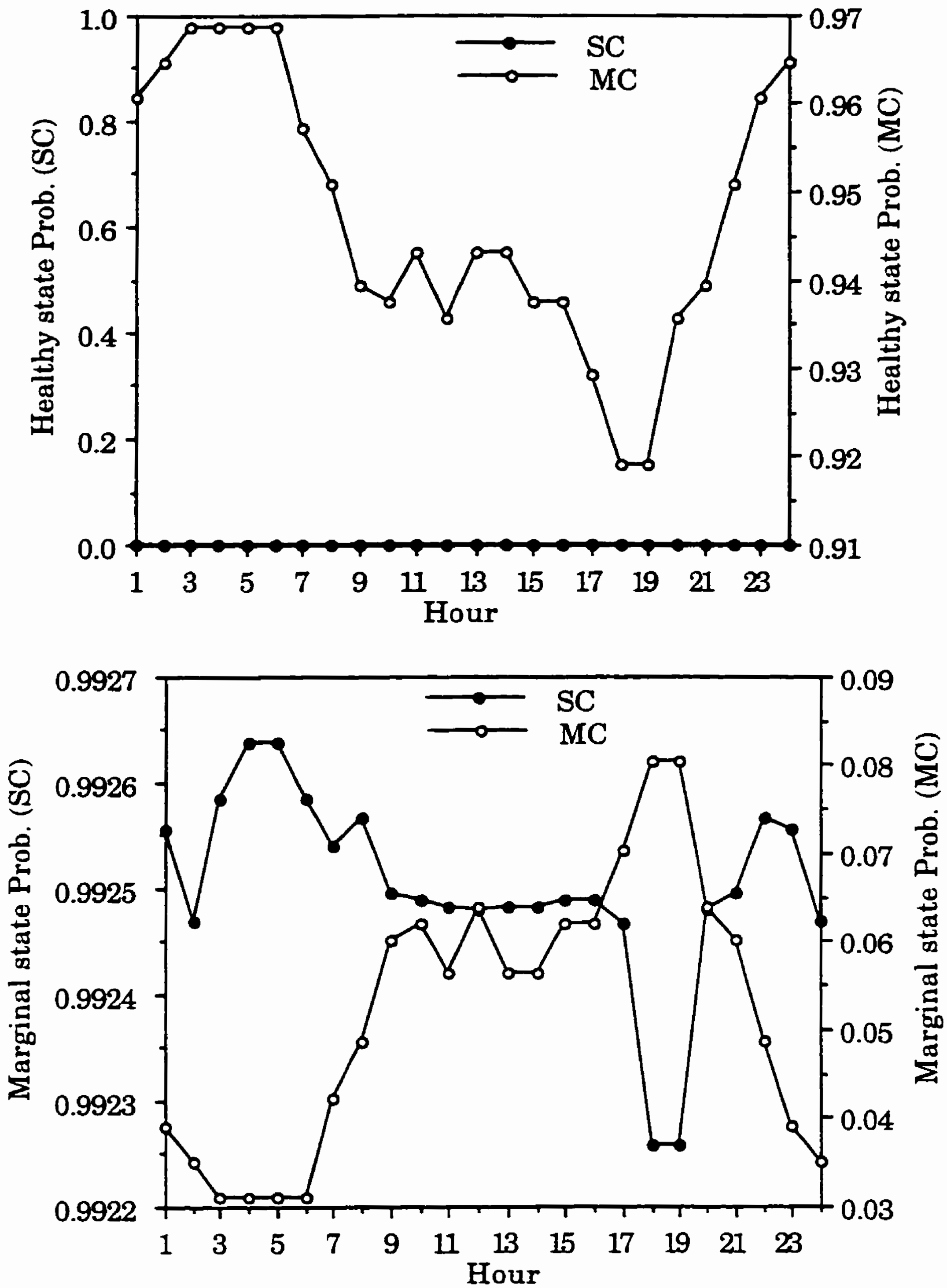

Figure 7.4: HLI healthy and marginal state probabilities.

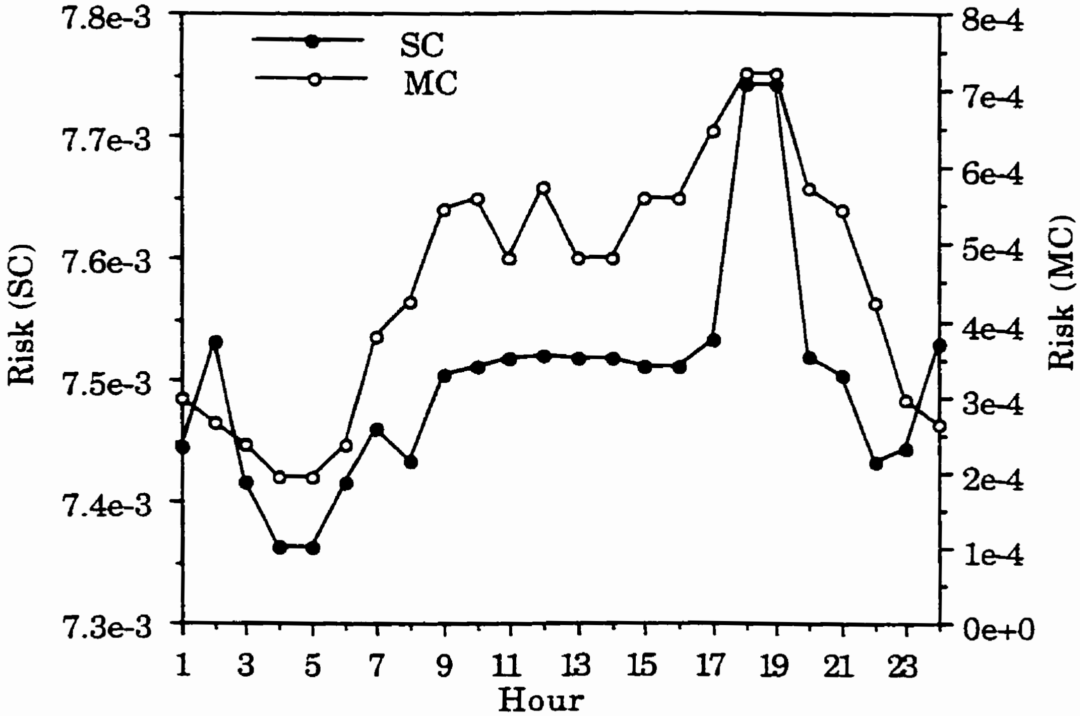

Figure 7.5: HLI risk state probability.

7.6.2 Hierarchical Level Two Unit Commitment Evaluation

Once the number of committed units at HLI has been determined, the next step is to satisfy the HLII unit commitment criteria, which could be the same as those used at HLI or some other desired values. In the studies presented in this thesis, the same criteria are considered for unit commitment at HLII. The same lead time was also used for calculating the HLII system well being indices. The HLII unit commitment risk is evaluated using the algorithm shown in Figure 7.1. If the accepted criteria are not satisfied, units are committed from the merit order list until the criteria are satisfied. In this analysis, up to fourth-level generator outages, third-level line outages and third level line plus generator outages are considered. The analysis covers more than 99.996% of the total sample space at the system peak load of 2850 MW with 24 committed units. The remaining probabilities the higher level contingencies and are added to the probability of the risk state.

7.6.2.1 Hierarchical Level Two Unit Commitment Using a Single Criterion

The HLII well-being indices were calculated considering different security constraint sets using the committed units shown in Figure 7.3 for the SC. The system has zero healthy state probability at both HLI and HLII levels. Figure 7.6 shows the variations in the marginal and risk state probabilities. From the results it can be seen that the number of committed units in the HLI study provides an acceptable HLII single criterion, i.e. a specified risk of 0.01. The HLII risk is slightly higher than that at HLI for a given load level. The selected security constraint set also has an effect on the HLII system well-being indices. The number of contingencies which create problems increase when both the voltage (SII) and line-flow (SI) constraints are taken into account. Table 7.1 shows the HLI and HLII well-being indices for the peak load of 2850 MW with 24 committed units.

Table 7.1: Well-being indices at a load level of 2850 MW with 24 committed units.

	constraint	Health	Margin	Risk
HLI		0.0	0.99228090	0.00771910
HLII	SI	0.0	0.99222468	0.00777531
	SII	0.0	0.99202285	0.00797715
	SI+SII	0.0	0.99202149	0.0079785

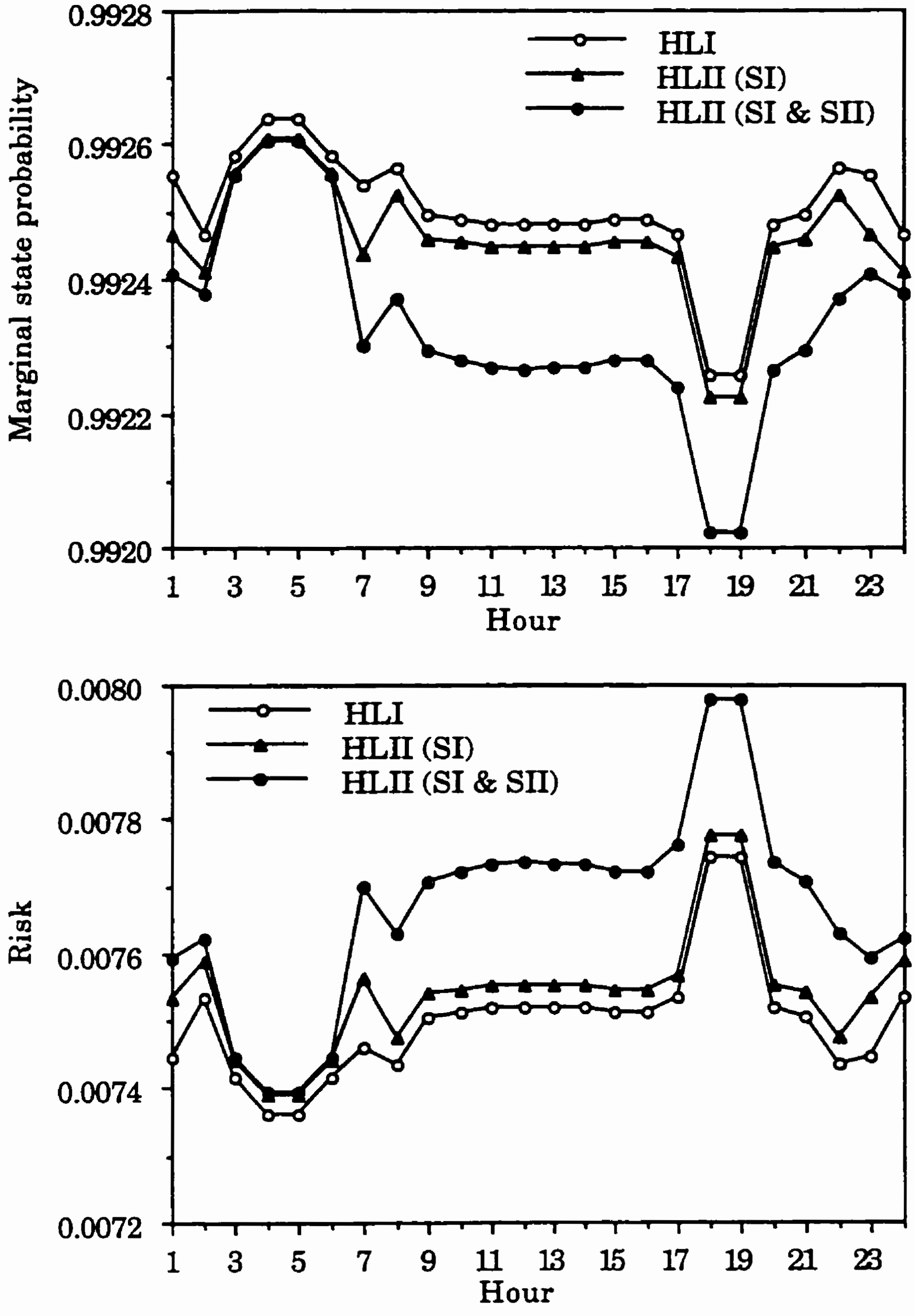

Figure 7.6: Comparison of HLI and HLII well-being indices with a single criterion.

7.6.2.2 Hierarchical Level Two Unit Commitment Using Multiple Criteria

The multiple criteria results shown in Figure 7.3, have HLI healthy state probabilities higher than 0.9 at all hours as shown by MC in Figure 7.4. The system may or may not satisfy multiple criteria at HLII with these committed units. If only line-flow constraints (SI) are considered in the analysis, multiple criteria are satisfied at all hours except hours 1, 2, 23 and 24. The reason for this is that two single level outages violate the constraint at these hours. Outage of Line 12 causes Line 13 to be overloaded and vice versa. The system is required to commit one or two additional units to those already committed at these hours in order to satisfy the multiple criteria. The number of committed units at hours 1 and 24 increase from 14 to 15 and those of hours 2 and 23 increase from 13 to 15. The HLII healthy state probabilities are therefore higher than those for the HLI study at these hours. Figures 7.7 and 7.8 show the associated HLI and HLII well-being indices for the 24 hour period where multiple criteria are satisfied at both HLI and HLII levels. It can be seen from these figures that for a given load level, the HLII healthy state probability is slightly lower than that of the HLI study provided that other conditions remain the same. The HLII risk, however, is greater than that at HLI.

The system has a zero HLII healthy state probability during the 24 hours when both security constraint sets are taken into account. The reason for this is that in addition to those single line outages which create overload problems at hours 1, 2, 23 and 24, there are single level line outages which create voltage problems at all hours. Table 7.2 shows the single level outages which create system problems at some load levels. The outage of Line 27 creates voltage problems at all hours. The results are tabulated in Table 7.3 for the system peak load of 2850 MW with 28 committed units. It can be seen from the results that for this system, the problems are more voltage than overload related.

Table 7.2: Single line outages which violate security constraints.

hour	load	No. of units	Single level contingencies
1	2045	13	L12, L13, L27
4	1740	12	L16, L17, L27
7	2170	15	L10, L27
18	2850	28	L4, L10, L27

Table 7.3: Well-being indices at a load level of 2850 MW with 28 committed units.

	constraint	Health	Margin	Risk
HLI		0.91916920	0.08011220	0.00071860
HLII	SI	0.90962074	0.08961307	0.00076619
	SII	0.0	0.99897779	0.00102221
	SI+SII	0.0	0.99897710	0.00102289

7.6.3 Effect of Lead Time Variation

Generating units are usually committed to the system for a specified time period during which additional generation can be made available after a time delay known as the system lead time. In the previous studies it was assumed that the IEEE-RTS has a lead time of 4 hours. Figures 7.9 and 7.10 show the impact on the HLI and HLII well-being indices of lead time variation. The HLII well-being indices were calculated using the number of committed units

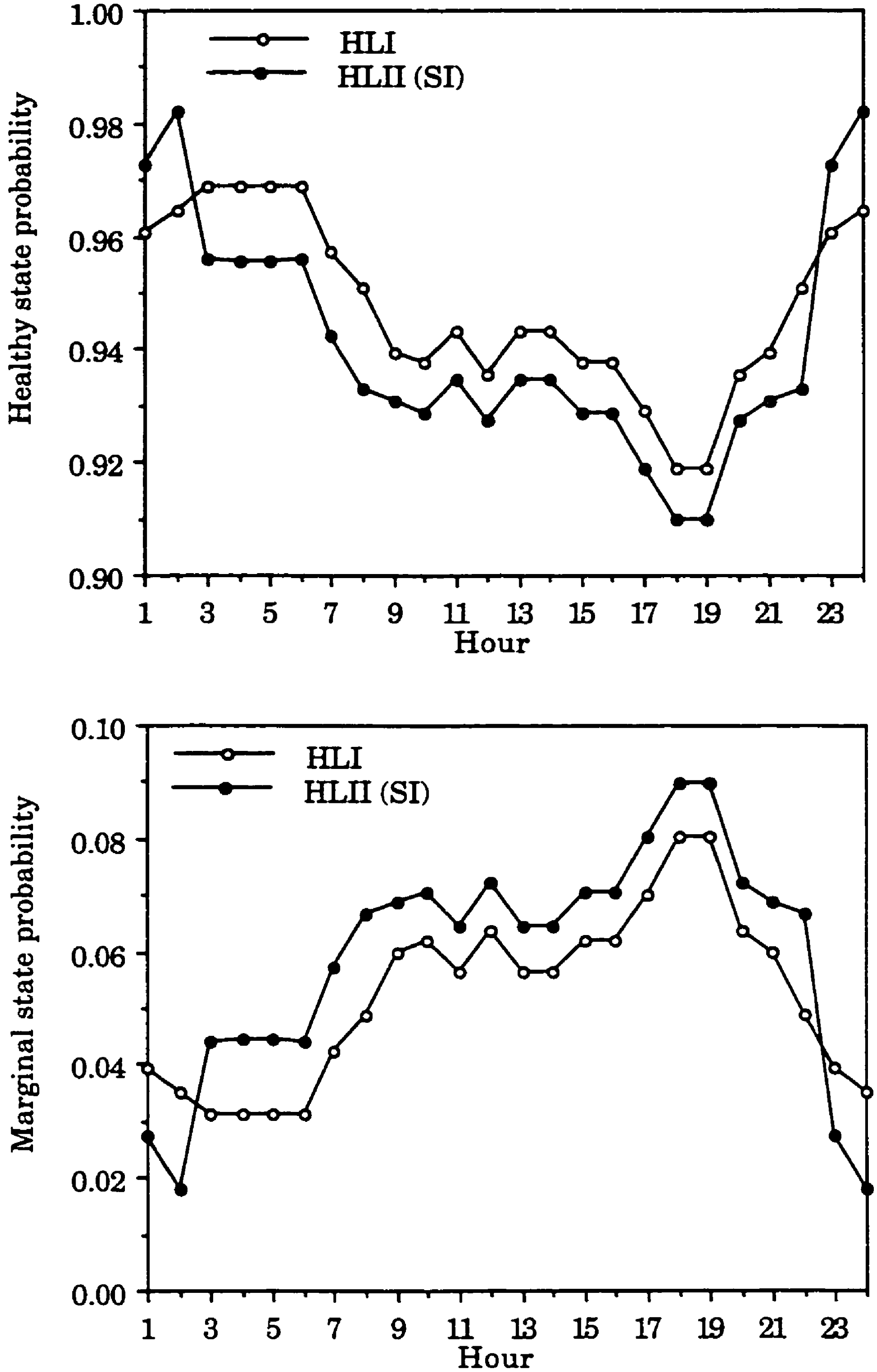

Figure 7.7: Comparison of the HLI and HLII healthy and marginal state probabilities for multiple criteria

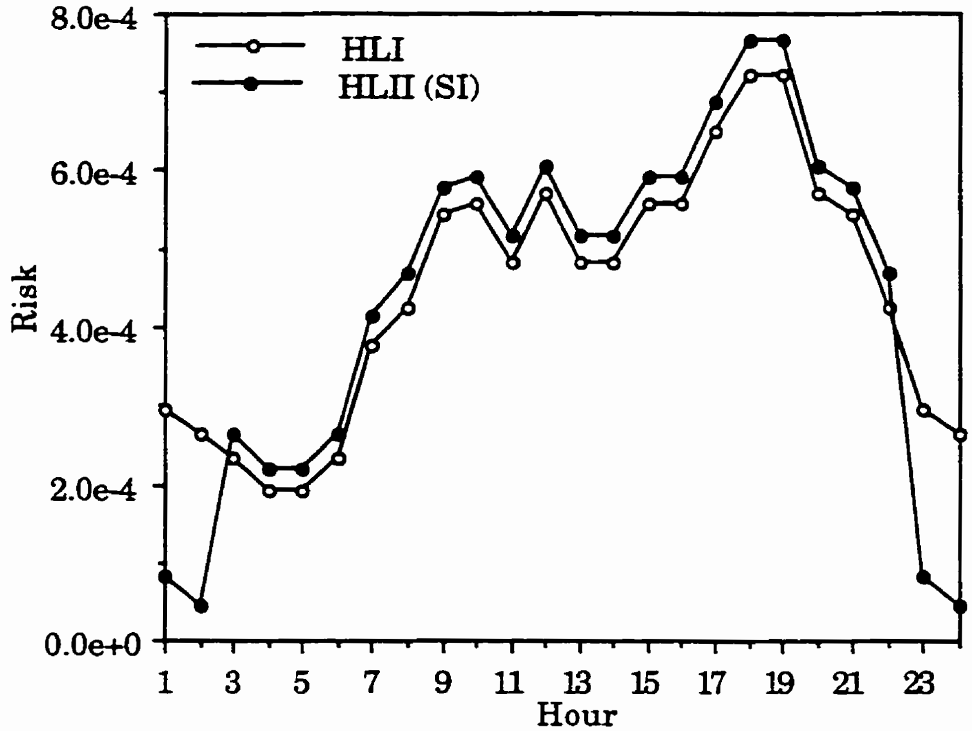

Figure 7.8: Comparison of the HLI and HLII risk state probabilities for multiple criteria

stated in Section 7.6.2.2. The system can satisfy HLI and HLII multiple criteria during the 24 hour period when only line overload (SI) is considered as a system problem and the system lead time is 4 hours. It can be seen from the results, that at any given hour the healthy state probability decreases as the system lead time increases. The risk state probability, however, increases as the lead time increases. The IEEE-RTS cannot satisfy the acceptable HLI and HLII healthy state probability of 0.9 at some of the load levels when the system lead time is more than 4 hours. The HLI and HLII healthy state probabilities decrease from 0.93942112 and 0.93060565 to 0.88231612 and 0.87351425 respectively at a load level of 2565 MW (hour 9 in Figure 7.9) with 19 committed units as the system lead time increases from 4 to 8 hours. The system is required to commit 20 units at this load level to satisfy the multiple criteria when the system lead time is 8 hours.

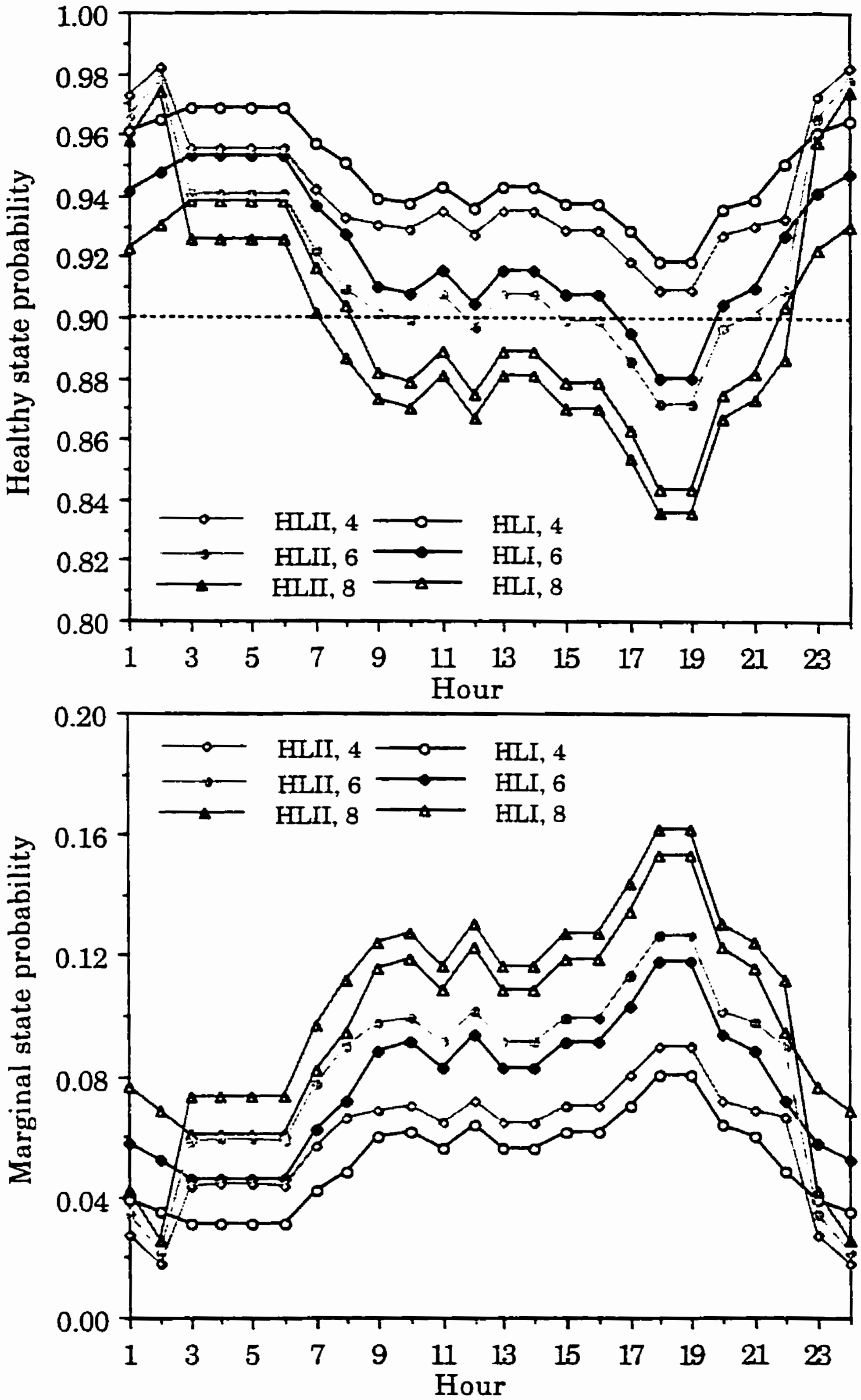

Figure 7.9: Variation of HLI and HLII system healthy and marginal indices versus lead time.

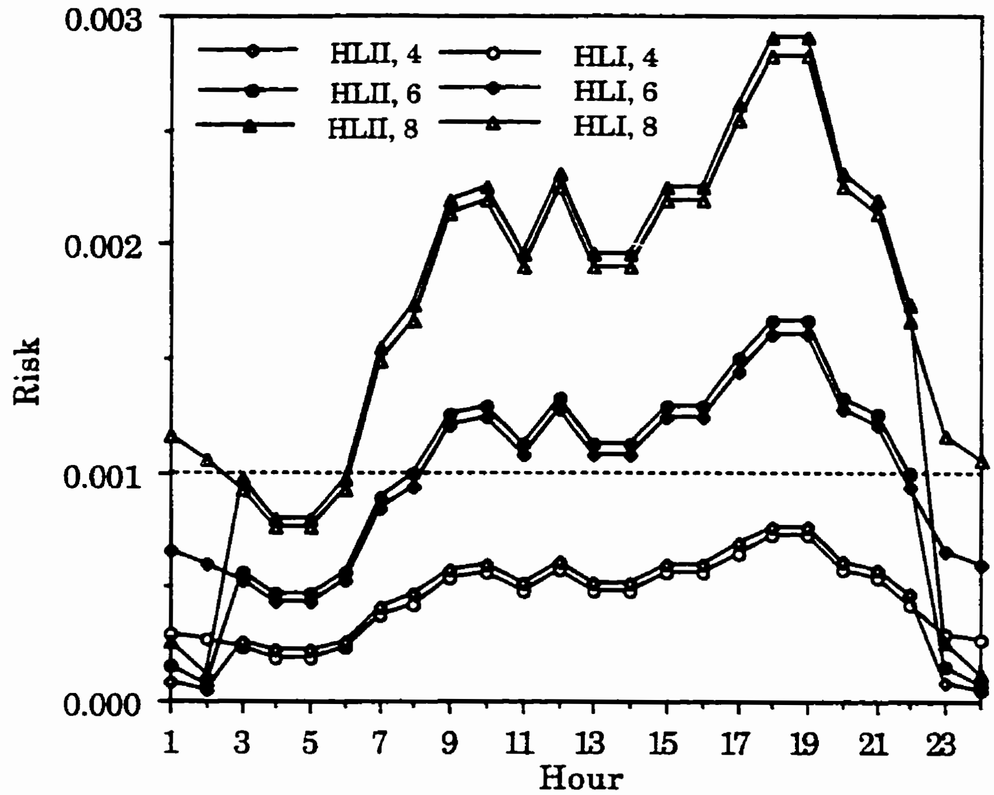

Figure 7.10: Variation of HLI and HLII system risk indices versus lead time.

7.7 Conclusions

This chapter extends the concepts of HLI unit commitment health analysis proposed in [60] to unit commitment in composite generation and transmission systems. The problem of unit commitment is decomposed into two subproblems. Generating units are first committed to the system based on the HLI operating criteria followed by unit commitment evaluation at HLII. The committed capacity should satisfy the operating criteria at both HLI and HLII levels. The required number of committed units and the associated well-being indices are very dependent on the selected security constraint sets. An approach is presented in this chapter to determine the operating state probabilities using a contingency enumeration technique. The results obtained for this system indicate that the number of committed units at HLI provides acceptable HLII operating state indices if only line-flow constraints are considered in the analysis. This, however, is not the case when voltage constraints are taken into account, due to the increased number of contingencies which create problems. It, therefore, can be concluded that in this system the HLII problems are more voltage than overload related.

Utilization of the well-being framework in unit commitment is a new concept, which while complementing the risk evaluation approach, also provides important information to system operators on the degree of system well-being. Its application at HLII provides interesting opportunities to evaluate the system support required to meet acceptable operating criteria in a deregulated utility system. Operating reserve in a system can be in the form of spinning reserve or stand-by reserve. Some utilities also consider interruptible load as a form of system reserve. In the studies reported in this chapter, it was assumed the system contains only spinning reserve. The implications of considering stand-by units and interruptible load are discussed in the next chapter.

8. UNIT COMMITMENT IN COMPOSITE GENERATION AND TRANSMISSION SYSTEMS CONSIDERING STAND-BY UNITS AND INTERRUPTIBLE LOAD

8.1 Introduction

The rapid growth of power networks and interconnections between utilities has led to the recognition that transmission networks play a critical role in determining overall system reliability. A power system operator is continuously faced with the problem of making good decisions rapidly. This imposes many burdens in order to ensure the system is operated economically but with an acceptable level of security. Security is achieved by maintaining extra operating capacity at all times. This extra capacity can be in the form of spinning reserve or stand-by capacity [3]. Some utilities also consider interruptible load as a part of operating reserve in emergency conditions or to reduce operating costs. Interruptible/curtailable load tariffs are one of the most frequent load management programs implemented by both U.S. investor-owned and publicly owned utilities [149,150]. Reference [151] illustrates an interruptible load program activated by the Taiwan Power Company in 1987. The term, interruptible load, has also been defined in [152] as a recallable commitment as opposed to versus non-recallable firm load. Recallable contracts are cut before non-recallable contracts to reestablish system security.

The basic concepts associated with unit commitment health analysis in composite generation and transmission systems are discussed in Chapter 7 where the operating reserve in the system consists of only spinning reserve. Stand-by units and interruptible load can be incorporated in the operating reserve assessment in composite generation and transmission systems using the concept of area risk curves [3]. Stand-by units and interruptible load can have considerable effect on composite system operating reserve assessment. The impact on the composite generation and transmission system well-being indices of variations in the size and location of rapid start and hot reserve units are examined in this chapter. A procedure has been developed to determine the required number of units for a given load level and the associated well-being indices. The impact of having generating capacity at different locations in a system should be of considerable interest in the new competitive environment.

8.2 Stand-by Units and Interruptible Load Models

The basic two state model does not contain sufficient detail to adequately represent stand-by units. A matter of concern when dealing with rapid start and hot reserve units is the possibility of their failure to start. The available state space models for such units can take this possibility into account [112,153]. This is discussed in Section 4.3 of Chapter 4. Rapid start units such as gas turbines can be represented by a four state model as shown in Figure 4.2. These units can be made available for service within minutes. Hot reserve units can be represented by a five state model as shown in Figure 4.3. The transition rates associated with the rapid start and hot reserve units are given in Appendix D. The time dependent state probabilities can be calculated using the matrix multiplication techniques presented in Section 4.3.

Interruptible load can be modeled as an equivalent generating unit with zero failure rate [38] or considered as a load variation, as shown in Figures 8.1 and 8.2 respectively. In this chapter the load variation model is used for the purpose of computational analysis.

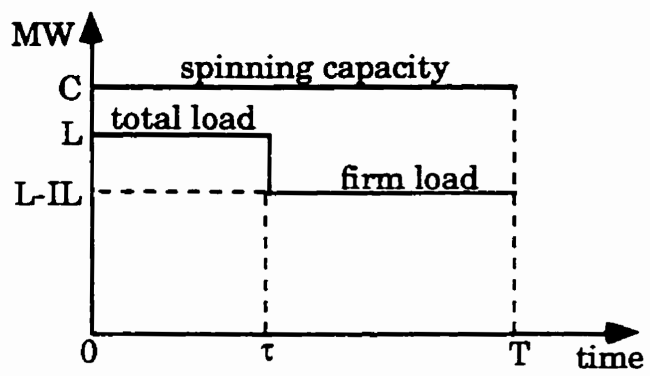

Figure 8.1: Load variation approach model for interruptible load.

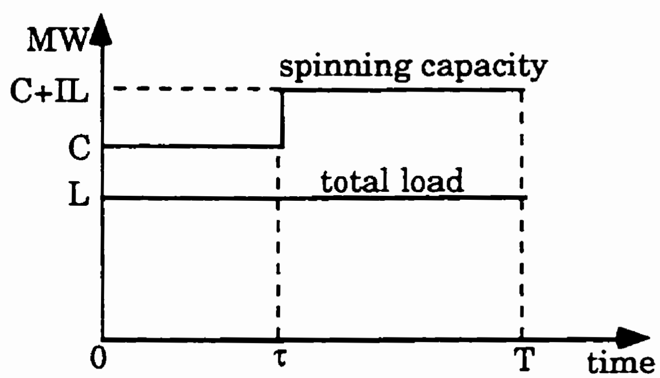

Figure 8.2: Equivalent unit approach model for interruptible load.

8.3 Problem Formulation

The problem of unit commitment in a composite generation and transmission system (HLII) can be decomposed into two subproblems. Generating units are first committed to the system such that the HLI operating criteria are satisfied. The number of committed units at HLI are then considered as the initial required number of committed units at HLII in subsequent evaluation of the HLII well-being indices.

8.3.1 Inclusion of Stand-by Units

Consider a system with n_r rapid start units and n_h hot reserve units requiring N_{si} units to be committed as spinning units to meet a given load level while satisfying the HLI operating criteria. The HLII well-being indices are calculated using area risk concepts. Figure 8.3(a) shows an area risk curve in which the reserve in the system is only spinning reserve. A typical area risk curve for a system with stand-by units is shown in Figure 8.3(b). Rapid start units become available at time t_r and the system risk decreases by D_{rs}. The system risk is further decreased by D_{rh} when hot reserve units become available at time t_h. At time t_a, additional units become available and the risk is negligible after this time. In this chapter, the number of committed units refers to the number of units which are spinning and does not include stand-by units. The HLII operating state probabilities based on the number of committed units and with the inclusion of stand-by units are calculated using the following procedure.

$$P_r^{HLII} = R_a + R_b + R_c \tag{8.1}$$

$$R_a = \int_0^{t_r} F_2(R)dt = P_{r1}^{HLII} \tag{8.2}$$

$$R_b = \int_{t_r}^{t_h} F_2(R)dt = P_{r3}^{HLII} - P_{r2}^{HLII} \tag{8.3}$$

$$R_c = \int_{t_h}^{t_a} F_2(R)dt = P_{r5}^{HLII} - P_{r4}^{HLII} \tag{8.4}$$

$$D_r = D_{rs} + D_{rh} \tag{8.5}$$

$$P_r^{HLII} = P_{rs}^{HLII} - D_r \tag{8.6}$$

$$P_r^{HLII} = 1 - P_{hs}^{HLII} - P_{ms}^{HLII} - D_r \tag{8.7}$$

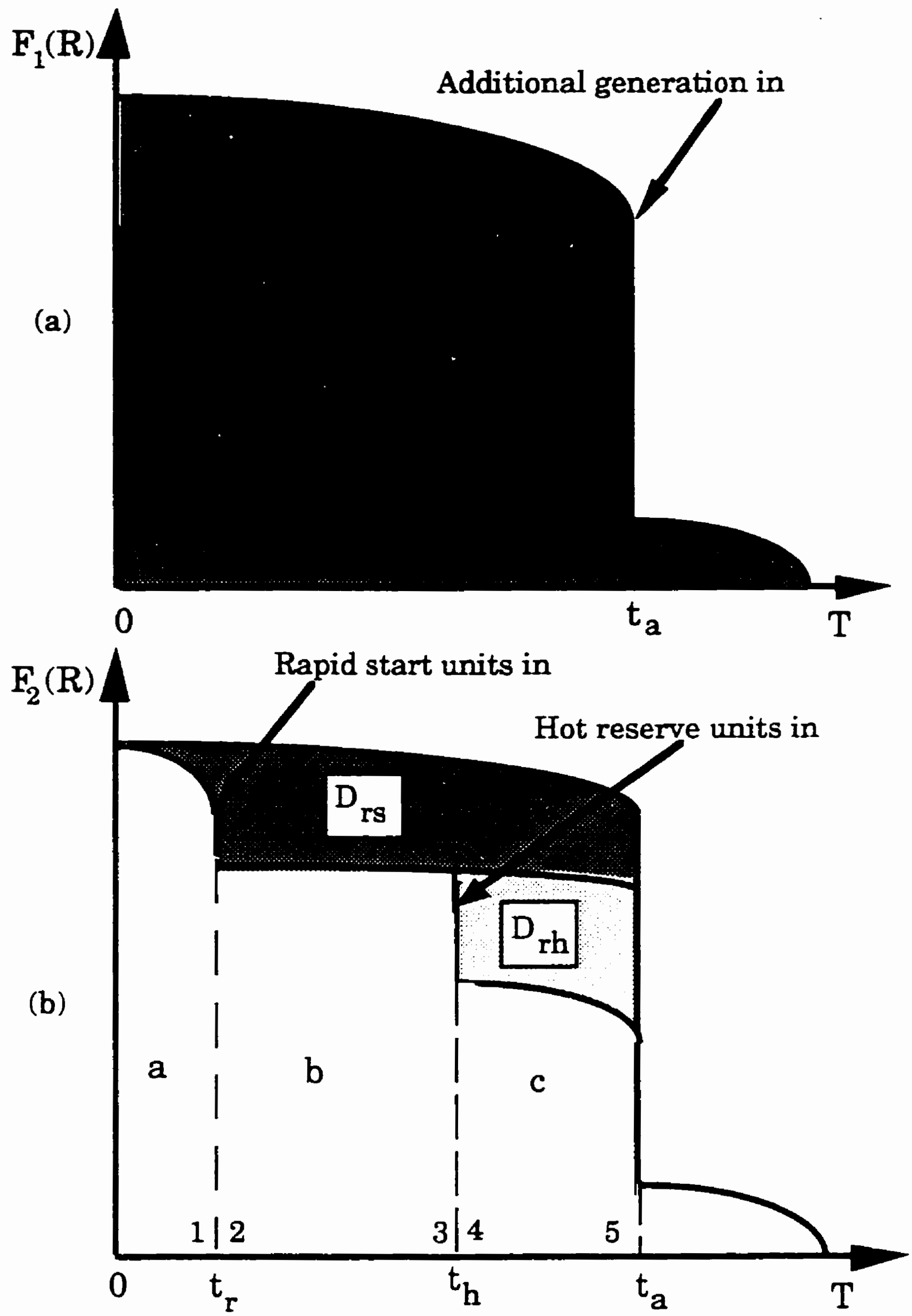

Figure 8.3: Area risk function without (a) and with (b) stand-by units.

Adding and subtracting $(P_{hs}^{HLII} + P_{ms}^{HLII})D_r$ on the right hand side of Equation 8.7 gives,

$$P_r^{HLII} = 1 - P_{hs}^{HLII} - P_{ms}^{HLII} - D_r + (P_{hs}^{HLII} + P_{ms}^{HLII})D_r \\ -(P_{hs}^{HLII} + P_{ms}^{HLII})D_r \tag{8.8}$$

In addition, the system risk can be defined using Equation 8.9:

$$P_r^{HLII} = 1 - P_h^{HLII} - P_m^{HLII} \tag{8.9}$$

Regrouping the terms in Equation 8.8 and using Equation 8.9 gives:

$$P_h^{HLII} = P_{hs}^{HLII}(1 + D_r) + P_{rs}^{HLII} D_r \tag{8.10}$$

$$P_m^{HLII} = P_{ms}^{HLII}(1 + D_r) \tag{8.11}$$

where

$F_1(R)$,	HLII area risk function with only spinning reserve,
$F_2(R)$,	HLII area risk function with the inclusion of stand-by units,
R_a, R_b, R_c	Partial risks in the area risk curve,
D_r	Total decrease in risk,
$D_{rs},\ D_{rh}$	Decreased risk due to the inclusion of rapid start and hot reserve units respectively,
$P_h^{HLII}, P_m^{HLII}, P_r^{HLII}$	Calculated HLII healthy, marginal and risk state probabilities using area risk function $F_2(R)$,
$P_{hs}^{HLII}, P_{ms}^{HLII}, P_{rs}^{HLII}$	Calculated HLII healthy, marginal and risk state probabilities considering only spinning reserve using area risk function $F_1(R)$,
$t_r,\ t_h$	Lead time of rapid start and hot reserve units respectively,
t_a	Lead time of additional generating units,
$n_r,\ n_h$	Number of rapid start and hot reserve units respectively,

The operating state probabilities can be calculated using a contingency enumeration technique. A hybrid approach is used in this chapter to calculate the HLII operating state probabilities. Considering a given set of HLII security constraints, the system is either in the risk or not at risk state for a given outage level. The not at risk state reflects the system ability to operate with no constraints being violated, i.e. the system is in either the healthy or marginal state. As previously noted, the decision on whether the contingency belongs to the healthy or marginal state involves an analysis of all possible next level outages involving that particular outage. It is, therefore necessary to keep a record of the contingency states and to update these records as the enumeration proceeds. This can lead to additional memory requirements and computation time particularly when the size of the system and the number of units, both spinning and stand-by, are large.

In order to decrease both the computation time and the memory requirement, the partial risks for the different periods shown in Figure 8.3(a) are calculated considering the system operating states as being in either the risk or not at risk state. It is, therefore, not necessary to keep a record of each contingency level when calculating the partial risks in different periods. Using the above procedure, once the HLII risk state probability is calculated, it is compared with the specified value. The basic objective is to satisfy a specified HLII risk as expressed in Equation 8.12.

$$P_r^{HLII} \leq SP_r^{HLII} \tag{8.12}$$

where SP_r^{HLII} is the HLII specified system risk state probability.

If Equation 8.12 is not satisfied, one more unit must be committed to those already committed and the procedure continued until it is satisfied. It should be noted that during this procedure, no healthy or marginal state probabilities need to be calculated to satisfy Equation 8.12. Assume that the system needs N_{sii} committed units to satisfy Equation 8.12. Once the single risk criterion (Equation 8.12) is satisfied, the HLII healthy, marginal and risk state probabilities are calculated considering only the spinning units (N_{sii}). The final HLII healthy and marginal state probabilities are then calculated using Equations 8.10 and 8.11. If only a single risk criterion must be satisfied, the procedure is terminated at this point. The procedure must be continued until Equation 8.13 is also satisfied in the case of multiple criteria.

$$P_h^{HLII} \geq SP_h^{HLII} \tag{8.13}$$

where SP_h^{HLII} is the HLII specified system healthy state probability.

8.3.2 Inclusion of Interruptible Load

The presence of interruptible loads can affect the composite well-being indices. Load curtailment can be considered as a means of reducing system risk when necessary and stand-by units are unavailable [38]. A basic requirement is a rate structure which provide incentives to both the utility and the customer. The customer then agrees to reduce its demand as and when requested by the utility. Reduction can be achieved by automatic or manual control. No matter what control methods are used, a relatively short notice must be issued by the operator prior to the load interruption. This time period is designated as the interruptible load lead time.

Controlled load interruption can be considered as an ability to bring ready reserve into the system depending on the allowable time delay of the load interruption. As discussed in Chapter 6, the effect of interruptible loads can be incorporated in operating reserve assessment using the concept of area risk curves. A typical area risk curve for a system with an interruptible load is shown in Figure 8.4 (i.e. lower curve, in which τ and t_a are the time of load interruption and the time required to bring additional units into service respectively.

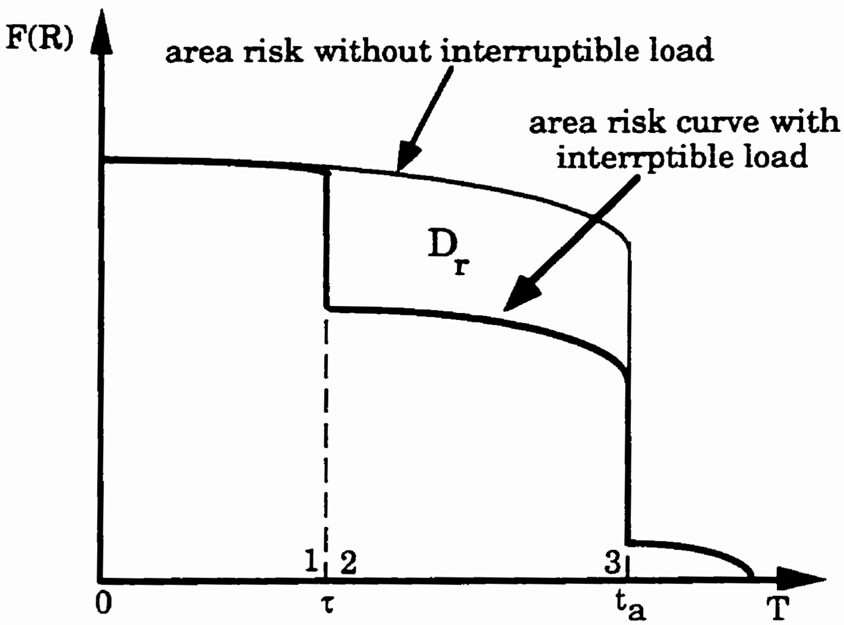

Figure 8.4: Area risk curve for load interruption.

The total load, which is the summation of the firm load and the interruptible load is required to be supplied in the period 0 to τ. In the next period τ to t_a only the firm load remains. At time τ, LI MW of load is interrupted and the risk contribution decreases. The composite well-being indices for the entire lead time can be evaluated using a similar technique to that utilized for rapid start and hot reserve units.

Unit commitment procedure can be summarized as follows:

A1. Specify the HLI operating criteria,

A2. Determine the required number of committed units in HLI, B1. Consider the number of committed units in Step A2 as the initial number of committed units for HLII and define HLII operating criteria,

B2. Calculate the HLII risk state probability using Equation 8.1,

B3. If the specified HLII risk is satisfied, go to Step B5, otherwise go to Step B4,

B4. Add one unit to the already committed units and go to Step B2,

B5. Calculate HLII healthy and marginal state probabilities using Equations 8.10 and 8.11,

B6. For multiple criteria go to Step B7, otherwise go to Step B8,

B7. If specified HLII healthy state probability is satisfied go to Step B8, otherwise go to Step B4.

B8. Stop.

The proposed technique is illustrated by application to the IEEE-RTS in the next section.

8.4 Application to the IEEE Reliability Test System

The single diagram of the IEEE-RTS is shown in Figure 2.3. As noted in Chapter 7, the outage of line 11 will cause complete isolation of Bus 7. The probability of the healthy state will therefore be zero using the criterion that the loss of any single element will not result in a limit being violated or load curtailment. Outage of Line 11, therefore, has been considered as a special case, which does not violate the healthy state definition. Four different studies have been performed. In each study, HLI indices were evaluated followed by HLII assessment. The first study provides a set of basic results when the reserve in the system is only in the form of spinning reserve. In the second and the third cases, rapid start and hot reserve units are included in the analysis. Interruptible load is included in the analysis in the fourth study. Unit commitment is done considering both single and multiple criteria.

The single criterion is a specified risk of 0.01, while in the multiple criteria case, an acceptable healthy state probability of 0.9 must be satisfied in addition to a specified risk of 0.01. In these analyses, up to fourth level generator outages, third level line outages and third level line plus generator outages are considered. The system is assumed to be operating in the risk state for higher order outages.

8.4.1 Basic Study Results

Table 8.1 shows the required amount of spinning capacity for different load levels considering the single criterion at HLI where OR represents the amount of operating reserve at the given load level and the corresponding number of committed units. The healthy state probability is zero for some load levels due to insufficient spinning reserve. Table 8.2 shows the results when the multiple criteria are applied.

Table 8.1: HLI unit commitment (single criterion).

load	units	OR	Health	Margin	Risk
1425	10	516	0.97684725	0.02298005	0.00017271
1995	13	411	0.95691649	0.04272104	0.00036247
2280	15	381	0	0.99254908	0.00745092
2850	24	351	0	0.99228091	0.00771909

Table 8.2: HLI unit commitment (multiple criteria)

load	units	OR	Health	Margin	Risk
1425	10	516	0.97684725	0.02298005	0.00017271
1995	13	411	0.95691649	0.04272104	0.00036247
2280	16	481	0.95424218	0.04536093	0.00039689
2850	28	415	0.91916923	0.08011214	0.00071863

The HLII results are very dependent on the security constraints considered. The security constraints associated with composite systems are discussed in Chapter 7. Tables 8.3 and 8.4 show the HLII results when line flow constraints are included in addition to the HLI security constraint. In Table 8.3, the system healthy state probability is zero for almost all the load levels. The reason for this is that in addition to the single unit outage violations (Units 5, 6) single line outages also create a system problem. The committed capacity at HLI, however, is sufficient to satisfy the HLII single risk criterion. Comparing the results shown in Tables 8.3 and 8.4 with those of Tables 8.1 and 8.2, it can be seen that for a given load level and the corresponding number of committed units, the HLII risk is higher than that of HLI due to the inclusion of transmission line constraints. The results presented in Table 8.4 show that the committed capacity for satisfying the multiple criteria at HLI can satisfy the multiple criteria at HLII except at the 1995 MW load level. The reason for this is that a single outage of either Line 12 or 13 will result in overload in the other. It can be seen from the system topology that this problem can be overcome by committing additional capacity at Bus 7. The system, therefore, should commit 15 units, i.e. two units more than those required to satisfy multiple criteria at HLI, in order to satisfy the multiple criteria at HLII using the priority loading order given in Table 2.1. The system could also satisfy the criteria by changing the priority loading order and committing Unit 15 (at Bus 7) after committing Unit 13 (at Bus 23). In this case, the system is required to commit only one more unit to the 13 already committed units. The results for these two cases are shown in Table 8.5. These results can assist the system operator to decide which unit should be committed to satisfy the operating criteria at the lowest operating cost. The operating costs for the three cases in Table 8.5 are \$19381.05, \$19970.34 and \$20065.26/hour respectively.

Table 8.3: HLII unit commitment (single criterion).

load	units	OR	Health	Margin	Risk
1425	10	516	0.96585034	0.03395056	0.00019910
1995	13	411	0.0	0.99957668	0.00042332
2280	15	381	0.0	0.99248221	0.00765954
2850	24	351	0.0	0.99222458	0.00777542

Table 8.4: HLII unit commitment (multiple criteria).

load	units	OR	Health	Margin	Risk
1425	10	516	0.96585034	0.03395056	0.00019910
1995	13	411	0.0	0.99957668	0.00042332
2280	16	481	0.93795746	0.06158670	0.00045583
2850	28	415	0.90866715	0.09056587	0.00076698

Table 8.5: Various options in unit commitment at a load level of 1995 MW.

load	units	OR	Health	Margin	Risk
1995	13	411	0.0	0.99957668	0.00042332
1995	14	511	0.94683872	0.05285679	0.00030449
1995	15	666	0.96963992	0.03027489	0.00008519

The HLII results change significantly when voltage constraints are also considered. The committed capacity at HLI shown in Table 8.1 can satisfy the single risk criterion at HLII even with the inclusion of voltage constraints. The system risk, however, increases compared to that shown in Table 8.3. The reason for this is that some of the contingencies which belong to the marginal state transfer to the risk state by including voltage constraints in the analysis. The system risk at the load level of 2850 MW with 28 committed units increases from 0.00076698 to 0.00103144 when voltage constraints are added to the line flow constraints considered. The system also cannot satisfy the HLII healthy state probability of 0.9 with the committed capacity shown in Table 8.4 when both voltage and line flow constraints are considered. The reason for this is that at all load levels there are some single level line outages which create voltage problems. The system has zero healthy state probability at the load level of 2850 MW with 28 committed units when voltage constraints are considered, compared to 0.90866715 when only line flow constraints are considered.

8.4.2 Results with the Inclusion of Rapid Start Units

It was assumed in the base case studies that the reserve in the system is only spinning reserve. The IEEE-RTS has a number of gas turbine rapid start units which are assumed to be available within 10 minutes [115]. Table 8.6 shows the required number of committed units at HLI for different load levels when the system has two 25 MW gas turbine units in addition to the generating units given in Table 2.1. The generating units were committed to the system using both the single and multiple criteria [61]. It should be noted that spinning reserve is the spinning capacity in excess of the system load and operating reserve is the summation of spinning reserve and all other types of reserve in the system, such as stand-by reserve and interruptible load. The location of rapid start units is not considered in HLI analysis. In order to conduct HLII unit commitment assessment, it was assumed that the gas turbine units are connected at Bus 1.

Table 8.6: HLI unit commitment including two 25 MW rapid start units.

load MW	single criterion				multiple criteria			
	units	SPC	SR	OR	units	SPC	SR	OR
1425	9	1744	319	369	10	1941	516	566
1995	13	2406	411	461	13	2406	411	461
2280	15	2661	381	431	16	2761	481	531
2850	21	3165	315	365	28	3265	415	465

SPC =Spinning capacity
SR =Spinning reserve
OR =Operating reserve

Table 8.7 shows the HLII results with the single criterion considering the number of committed units shown in Table 8.6. The line flow and power constraints (SI) are considered as security constraints. Compared to the results shown in Table 8.3, it can be seen that at some load levels, the system requires less spinning reserve with the inclusion of rapid start units. Table 8.8 shows the HLII results when the voltage constraint (SII) is added to the constraints already considered in Table 8.7. Compared to the results shown in Table 8.7, it can be seen that the system risk increases for a given load level. The reason for this is that some of the contingencies which previously belonged to the marginal state transfer to the risk state due to voltage constraint violations.

Table 8.7: HLII unit commitment (single criterion and SI constraint).

load	units	OR	Health	Margin	Risk
1425	9	369	0.00001953	0.99101539	0.00896508
1995	13	461	0.00000002	0.99962930	0.00037068
2280	15	431	0.00004737	0.99873702	0.00121561
2850	21	365	0.00002070	0.99081679	0.00916251

Table 8.8: HLII unit commitment (single criterion and SI+SII constraints).

load	units	OR	Health	Margin	Risk
1425	9	369	0.00001539	0.99042971	0.00955490
1995	13	461	0.0	0.99954982	0.00045018
2280	15	431	0.00004695	0.99842409	0.00152895
2850	21	365	0.00001943	0.99048259	0.00949798

Table 8.9 shows the HLII results when the system is required to satisfy multiple criteria. The required number of units increases to that shown in Tables 8.4 and 8.5, even with the inclusion of rapid start units. The reason for this is that rapid start units cannot transfer the system to the healthy state if it is initially operating in the marginal state [61]. Voltage constraints are included in the results shown in Table 8.10, where it can be seen that the system is not able to satisfy a healthy state probability of 0.9. The HLII multiple criteria are not satisfied, even by committing additional units. The results show that the system problems are voltage rather than line flow related.

Table 8.9: HLII unit commitment (multiple criteria and SI constraint)

load	units	OR	Health	Margin	Risk
1425	10	566	0.96588526	0.03395179	0.00016295
1995	14	565	0.94573389	0.05405328	0.00021283
2280	16	531	0.93807005	0.06159410	0.00033585
2850	28	465	0.90887663	0.09058673	0.00053664

Table 8.10: HLII unit commitment (multiple criteria and SI +SII constraints)

load	units	OR	Health	Margin	Risk
1425	10	566	0.00000004	0.99963819	0.00036177
1995	14	565	0.00000002	0.99970507	0.00029491
2280	16	531	0.00000012	0.99958245	0.00041743
2850	28	465	0.00000012	0.99908655	0.00091333

In the results presented in Tables 8.7 to 8.10, it was assumed that the two gas turbine units were connected at Bus 1. The system well-being can be affected by varying the location and size of the rapid start units. The most suitable location to insert a unit can be determined by examining the system contingencies, particularly single level contingencies and their consequences. Determination of the optimum location of rapid start units was not considered in these studies and only the impact of changing the location was examined.

At most load levels, single level outages of Lines 4, 10 and 27 violates the voltage limits at Buses 4, 5 and 3 respectively. At a load level of 1995 MW and 13 committed units, single level outages of Lines 12 and 13 violate the line flow limits and the single outage of Line 27 creates system voltage problems. Consider that the two 25 MW gas turbine units are connected at Buses 7 and 3 (one at each). The system has a risk state probability of 0.000395 at the 1995 MW load level, with 13 committed units and the two 25 MW gas turbine units connected to Buses 7 and 3. The system risk decreases compared to the case when the two gas turbine units are connected at Bus 1 with a risk of 0.00045018 (Table 8.8). The system health varies slightly because it depends mostly on the amount of spinning reserve in the system or the healthy state probability without the stand-by units (Equation 8.10). The system cannot transfer to the healthy state by changing the location of the rapid start units, if it is initially operating in the marginal state.

No single level outage creates voltage or line flow problems when the system is at the load level of 1995 MW and commits 13 units assuming that the two 25 MW rapid start units are available at the decision time of t=0. The system health, margin and risk state probabilities are 0.94975922, 0.04969407 and 0.00054671 respectively. This, however, cannot be achieved by committing additional units based on the priority loading order given in Table 2.1. Committing 14 or 15 units can overcome the line flow problem as shown in Table 8.5 but the voltage constraint is still violated with the single level outage of Line 27. It should be noted that in this case, the two units are considered as spinning units.

8.4.3 Results with the Inclusion of Hot Reserve Unit

The lead time associated with a conventional thermal unit can be reduced by maintaining the boiler in a hot state. Assume that this is the case with one of the 100 MW units at Bus 7. The priority loading order shown in Table 2.1 is therefore modified by removing one of the 100 MW units from Bus 7. The number of generating units in the table is now 31. Unit commitment was performed for two load levels of 2280 and 2850 MW considering the 100 MW hot reserve unit with single criterion (SC) and multiple criteria (MC). As shown in Table 8.11 the system is now required to commit 14 or 16 units respectively for a load of 2280 MW to satisfy the single or multiple HLI criteria.

Table 8.11:HLI unit commitment including one 100 MW hot reserve unit.

Criterion	load	units	SPC	Health	Margin	Risk
SC	2280	14	2561	0.00002949	0.99156458	0.00840593
	2850	23	3101	0.00003048	0.99129362	0.00867590
MC	2280	16	2761	0.95447090	0.04537180	0.00015730
	2850	31	3305	0.94614372	0.05358464	0.00027164

The HLII well-being indices were determined using the proposed approach. It should be noted that when only hot reserve units are included in the analysis, the calculations for Periods 1 and 2 of the area risk curve are not necessary. Table 8.12 shows HLII results considering the line flow constraint set (SI). The system at the load level of 2280 MW with 14 committed units and without the hot reserve unit has HLII healthy, marginal and risk state probabilities of 0.0, 0.98879124 and 0.01120876 respectively. In this case not even the single risk criterion is satisfied. There are three single generating unit outages and two single line outages which violate the security constraints. The system risk decreases to 0.0085229 when a 100 MW hot reserve unit connected at Bus 7 is included in the analysis. The system can satisfy the HLII multiple criteria only when two more units are committed to the system. With 16 committed units at the 2280 MW load level, the system has 481 MW of spinning reserve and 581 MW of operating reserve. Table 8.13 shows the HLII results when voltage constraints (SII) are also added to the security constraint set. The system risk increases with the inclusion of more constraints provided that the other parameters remain the same. The system cannot satisfy multiple criteria even by committing 16 units. The reason for this is that single level outages of Lines 4, 10 and 27 create voltage problems.

Table 8.12: HLII unit commitment including one 100 MW hot reserve unit. (SI)

load	units	OR	Health	Margin	Risk
2280	14	381	0.00003011	0.99144699	0.00852290
2280	15	481	0.00003854	0.99756946	0.00239201
2850	23	351	0.00003094	0.99125131	0.00871775
2280	16	581	0.93820150	0.06160273	0.00019577
2850	31	555	0.93132743	0.06846965	0.00020292

Table 8.13: HLII unit commitment including one 100 MW hot reserve unit. (SI+SII)

load	units	OR	Health	Margin	Risk
2280	14	381	0.00002983	0.99125934	0.00871083
2280	15	481	0.00003877	0.99736337	0.00259786
2850	23	351	0.00003082	0.99100597	0.00896321
2280	16	581	0.00000013	0.99959014	0.00040973
2850	31	555	0.00000049	0.99935896	0.00064055

As in the case of rapid start units, varying the location and the size of hot reserve units cannot transfer the system to the healthy state if it is originally operating in the marginal state. The system with 16 committed units and no stand-by units has healthy, marginal and risk state probabilities of 0.0, 0.99937988 and 0.00062012 respectively. The inclusion of a 100 MW hot reserve unit has little effect on the system health as can be seen from Table 8.13. The system risk decreases by 34% with the inclusion of the hot reserve unit.

Assuming that a 76 MW unit at Bus 1 is in the hot state, the system has healthy, marginal and risk state probabilities of 0.00002979, 0.99141907 and 0.00855114 respectively at the 2280 MW load level with 14 committed units. Comparing this with the results shown in Table 8.12, it can be seen that there is only a slight difference in the two cases. It can be concluded that if only a single risk criterion must be satisfied, then the inclusion of stand-by units can decrease the required amount of spinning reserve. This, however, is not the case if multiple HLII criteria are applied.

8.4.4 Results with the Inclusion of Interruptible Load

In order to illustrate the effect of interruptible load on the system operating state probabilities, it was assumed that the IEEE-RTS has the ability to interrupt 5% of its load within a time delay of 10 minutes. The required number of generating units and the system operating state probabilities has an HLI study are shown in Tables 8.14 and 8.15 for single and multiple criteria respectively using the technique presented in [61]. The system lead time is assumed to be 4 hours. Comparing the results shown in Table 8.14 with those shown in Table 8.1, it can be seen that the required number of committed units decreases with the inclusion of interruptible load as a part of operating reserve. The system, however, is required to commit more unit(s) to satisfy the multiple criteria as shown in Table 8.15. The

Table 8.14: HLI unit commitment with interruptible load (single criterion).

load	units	Int. load	OR	Health	Margin	Risk
1425	9	71.25	397.25	0.00003490	0.99248995	0.00747515
1995	12	99.75	355.75	0.00003624	0.99240992	0.00755384
2280	14	114.0	495.0	0.00003915	0.99242778	0.00753307
2850	20	142.5	493.5	0.00004471	0.99231192	0.00764337

Table 8.15: HLI unit commitment with interruptible load (multiple criteria)

load	units	Int. load	OR	Health	Margin	Risk
1425	10	71.25	587.25	0.9768891	0.02298103	0.00012987
1995	13	99.75	510.75	0.95701187	0.0427253	0.00026283
2280	16	114.0	595.0	0.95449268	0.04537283	0.00013448
2850	28	142.5	557.5	0.9196995	0.08015832	0.00014219

Int. = Interruptible load

number of committed units for a given load level in Table 8.15 is identical to that in Table 8.2. The reason for this is that the inclusion of interruptible load cannot transfer the system to the healthy state if it is initially operating in the marginal state [61].

Table 8.16 shows the HLII results when the system is required to satisfy a single criterion. The required number of units is identical to those shown in Table 8.14. Only line flow constraints are considered in the results presented in Table 8.16. This table shows the number of committed units at the corresponding load levels required to satisfy the single risk criterion when interruptible load is included in the analysis. It should be noted that these committed units cannot satisfy the single criterion without considering interruptible load. The system with 9 and 20 committed units at the 1425 and 2850 MW load levels has risk state probabilities of 0.01077763 and 0.01159134 respectively when the system has no interruptible load. The system well-being is affected by including voltage constraints in the analysis. The system risk at the load level of 2850 MW with 20 units increases from 0.00770106 to 0.00792252 when voltage constraints are added to the line flow constraints already considered.

Table 8.16: HLII unit commitment with interruptible load (single criterion).

load	units	Int.	OR	Health	Margin	Risk
1425	9	71.25	397.25	0.00003513	0.99244762	0.00751725
1995	12	99.75	355.75	0.00003659	0.99233391	0.00762950
2280	14	114.0	495.0	0.00003971	0.99228780	0.00767249
2850	20	142.5	493.5	0.00004509	0.99225385	0.00770106

Table 8.17 shows the HLII results when the system is required to satisfy multiple criteria. The system with 13 committed units at the load level of 1995 MW cannot satisfy the multiple criteria even with the inclusion of interruptible load. The reason for this is that single level outages of Lines 12 and 13 violate the line flow constraints. These violations cannot be overcome by increasing the amount of interruptible load or by decreasing the interruption time and can only be eliminated by committing additional unit(s). It can be concluded that similar to the case of stand-by units, the system cannot transfer to the healthy state by including interruptible load, if it is initially operating in the marginal state.

Table 8.17: HLII unit commitment with interruptible load (multiple criteria)

load	units	Int.	OR	Health	Margin	Risk
1425	10	71.25	587.25	0.96589198	0.03395202	0.00015600
1995	13	99.75	510.75	0.00000004	0.99967647	0.00032349
2280	16	114.0	595.0	0.93820435	0.06160290	0.00019274
2850	28	142.5	557.5	0.90918328	0.09061882	0.00019785

8.5 Conclusions

A security constrained reliability evaluation approach is presented in this chapter to assess overall generating unit operating reserve in a composite generation and transmission system using a well-being framework. Operating reserve in the system consists of spinning and stand-by reserves and interruptible load. The HLII well-being indices are calculated using a hybrid approach to save computation time and to decrease the memory requirement. The results presented indicate that composite generation and transmission system well-being indices and the required number of committed units are affected by the desired operating criteria, security constraint sets, size and location of stand-by units and interruptible load. Inclusion of stand-by capacity and interruptible load can decrease the required amount of spinning reserve when only a single risk criterion is utilized. This is not the case when multiple HLII unit commitment criteria are applied. The most suitable location for stand-by units can be determined by examining the system contingencies and their consequences. Varying the size and location of stand-by units, increasing the amount of interruptible load and decreasing the interruption time change the HLII well-being indices, but cannot transfer the system to the healthy state, if it is initially operating in the marginal state.

9. SUMMARY AND CONCLUSIONS

Operating reserve provides an electric power system with the ability to respond to unforeseen load changes and sudden generation outages and a wide range of techniques have been used to determine operating reserve requirements. Both deterministic and probabilistic techniques can be utilized to determine the required level of operating reserve to be maintained by a system. Deterministic approaches do not specifically recognize the probability of component failures in the assessment of operating reserve. Probabilistic techniques can be used to take into account the random outages of system components and other stochastic component behavior. Probabilistic approaches generally base the design and operating constraints on the criterion that the risk of certain events must not exceed a preselected limit. Many utilities still prefer to use a deterministic technique due to the difficulty in interpreting a numerical risk index and also the lack of sufficient information provided by a single index. There is also a considerable interest in utilities to embed deterministic considerations into the evaluation of probabilistic indices. A practical way to overcome these difficulties is to monitor the system well-being. The system well-being is described by a set of operating states designated as healthy, marginal and at risk. The events leading to each operating state can be identified and the probabilities associated with these operating states evaluated. The probabilities associated with the healthy and risk states can be considered as operating criteria. A probabilistic technique has been developed for unit commitment and assessment of generating system operating health, margin and risk in [54] and is briefly discussed in Chapter 2. The technique overcomes some of the difficulties in interpreting the risk index and also provides the system operator with important information on the degree of system well-being compared to that available from the basic probabilistic techniques. This technique has been extended in this research work to cover the overall area of operating reserve assessment.

Operating reserve evaluation involves two distinctly different aspects. The first is unit commitment, in which the system operator decides which units should be committed to satisfy the operating criteria presented in Chapter 2. The second aspect is associated with unit dispatch decisions and the evaluation of the response capability of the committed units. Both aspects are necessary to obtain a complete appraisal of the operating reserve requirement, i.e. these activities complement rather than substitute for each other. In the assessment of unit commitment, the operating state probabilities are calculated based on the total amount of spinning reserve in a system, where spinning reserve is defined as the difference between the total operating capacity and the system load. An assigned amount of spinning reserve must be available within a given period of time in the event of a sudden loss of generating capacity, unforeseen changes in the system load or any other contingency which results in a loss of capacity. The concepts of unit commitment health, margin and risk are extended in Chapter 3 to include the response capability of the committed units. A risk index designated as the GSRSR is defined as the load dispatch criterion. Once the number of committed units are determined, the spinning reserve should be allocated among the committed units to satisfy the response criterion. This criterion could be a specified GSRSR, an acceptable response health probability or both. The operating cost, however, varies with different response criteria. An algorithm is presented in this chapter to determine the required number of units and the optimal load dispatch of the committed units based on the unit commitment and response criteria. The results show that if a system has a high unit commitment healthy state probability it also has the potential to have a high response healthy state probability. This, however, depends upon the margin time, the response rate of the units and how the spinning reserve is allocated among the committed units.

The ability of a system to respond to sudden changes and to pick up load depends on its unit types. Thermal units can pick up 1-3% of their full output capacity in one minute. Rapid start units can pick up load in a relatively short period of time. These units, therefore, can participate in the response health, margin and risk constrained load dispatch if their lead time is less than the specified margin time. Interruptible load can also be considered as part of the response reserve. The effects on the response health, margin and risk probabilities of factors such as rapid start units, interruptible loads and postponable outages are illustrated and presented in Chapter 4. An important aspect of rapid start units and interruptible loads is that a system which is in the marginal response state because of insufficient response reserve can transfer to the healthy state when these elements are present. The results also show that for a given load dispatch, the response risk decreases by increasing the degree of postponability. The relationships between the unit commitment and the response health, margin and risk are pictorially illustrated in this chapter in order to make these concepts more understandable.

The reliability of a power system is, in general, greatly improved by interconnection with other power systems. Assessment of operating reserve requirements in an interconnected generating system should include not only the generation and load models of the participating systems, but also the tie-line model and the agreement between the interconnected systems. Assessment of unit commitment in two interconnected systems is illustrated in Chapter 5. The problem of interconnected system unit commitment is decomposed into two subproblems. Unit scheduling is first performed in each isolated system in accordance with the specified operating criterion. Once the required number of committed units in each area is determined, the next step is to satisfy the operating criterion associated with the overall interconnected system. The criterion could be a specified interconnected system risk, an acceptable interconnected healthy state probability or both. A procedure is illustrated in this chapter to determine the operating state probabilities for the overall interconnected system. The results presented show that system well-being can be considerably improved by interconnection with another system. Each system can operate at either the same or at a higher level of reliability with a lower reserve than would be required without interconnection. A number of studies are illustrated in Chapter 5 to evaluate the impact on the interconnected system well-being of factors such as peak load, lead time, tie-line carrying capabilities, load forecast uncertainty, degree of postponability and derated states.

A generation system with a given number of committed units can serve a target firm load level designated as the FLCC. Under normal operating conditions, the generating capacity in operation is greater than the firm load and with this number of committed units, the system may also be able to carry a limited amount of interruptible load on top of the firm load without violating the operating criterion. Under these conditions, a larger system load can be served without committing additional units other than those required to carry the firm load. This additional load must be capable of interruption at short notice, if required. The capability of a system to serve the additional interruptible load is designated as the system interruptible load carrying capability (ILCC). Chapter 6 presents a probabilistic technique to evaluate the ILCC in both isolated and interconnected generating systems. A set of ILCC is determined for a given number of committed units and the associated FLCC, which consists of different amounts of interruptible load and the associated lead times. The condition is then formulated as an optimization problem. The ILCC level which maximizes the expected energy supplied is taken from the set and designated as the OILCC of the generation system. The OILCC for two interconnected systems is determined by combining the two sets associated with the isolated systems. The interruption times are modified using an energy based approach to satisfy the interconnected system operating criteria defined in Chapter 5.

The techniques and the procedures presented in Chapters 2 to 6 are associated with conventional HLI operating health analysis, which is based on the major assumption that the committed units are connected to a single bus and serve the total system load demand at this bus. Transmission constraints and the actual physical location of the generating units are not included in the analysis. In an actual power system, the generating capacities and loads are usually dispersed throughout the system and are not concentrated at a single bus. In composite system studies (HL II), the simple generation/load model used in HLI is extended to include the bulk transmission facilities. The approach illustrated in Chapter 7 is a new technique for operating reserve evaluation which includes the ability of the transmission system to deliver the generated energy to the major load points. This approach provides a more realistic appraisal of well-being indices than a basic HLI evaluation. The problem of unit commitment is decomposed into two subproblems. Generating units are first committed to the system based on the HLI operating criteria followed by unit commitment evaluation at HLII. The committed capacity should satisfy the operating criteria at both HLI and HLII. The required number of committed units and the associated well-being indices are very dependent on the selected security constraint sets. An approach is presented in this chapter to determine the operating state probabilities using contingency enumeration techniques. The results obtained for the IEEE-RTS indicate that the number of committed units at HLI provides acceptable HLII operating state indices if only line-flow constraints are considered in the analysis. This, however, is not the case when the voltage constraints are included, due to the increased number of contingencies which create problems. This, however, is not a general system conclusion and each system must be evaluated on its own merits.

Operating reserve in a system can be in the form of spinning reserve or stand-by reserve. Some utilities also consider interruptible load as part of the system reserve. In the studies reported in Chapter 7, it was assumed that the system reserve is only spinning reserve. Recognition of stand-by units and interruptible load is discussed in Chapter 8. The HLII well-being indices are calculated using a hybrid approach to save computation time and decrease the memory requirement. The results presented indicate that composite generation and transmission system well-being indices and the required number of committed units are affected by the desired operating criteria, security constraint sets, size and location of stand-by units and interruptible load. Inclusion of stand-by capacity and interruptible load can decrease the required amount of spinning reserve only in those cases in which a single risk criterion is utilized. This, however, is not the case when multiple HLII unit commitment criteria are applied. The most suitable location for stand-by units can be determined by examining the system contingencies and their consequences. Varying the size and location of stand-by units, increasing the amount of interruptible load and decreasing the interruption time change the HLII well-being indices, but cannot transfer the system to the healthy state if it is initially operating in the marginal state.

The developed methods and techniques presented in this thesis have been applied to the two reliability test systems, the IEEE-Reliability Test System (IEEE-RTS) and the Roy Billinton Test System (RBTS). The results obtained by utilizing the IEEE-RTS are illustrated in Chapters 2,3,4,5,6,7 and 8. Appendix A presents the results obtained utilizing the RBTS.

In conclusion, utilization of the well being framework in operating reserve assessment is a new concept, which while complementing the risk evaluation approach, also provides important information to system operators on the degree of system well-being. It is expected that the well-being framework and the concepts developed in this research work will prove extremely useful in the new competitive utility environment.

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A. APPLICATION TO THE ROY BILLINTON TEST SYSTEM

A.1 Introduction

Many techniques have been developed for conducting power system reliability analysis[13-17]. The literature also contains reference or "test" systems to provide a basis for testing and comparing the results obtained from alternate methods. Two basic reliability test systems, the Institute of Electrical and Electronic Engineering Reliability Test System (IEEE-RTS) [89] and the Roy Billinton Test System (RBTS) [154,155], have been published. The IEEE-RTS is a relatively large power system in which sufficient complexity and detail have been included to make the test system representative of an actual utility system. The system was described in Section 2.7 of Chapter 2. The application of the system well-being concepts in operating reserve assessment are illustrated in this thesis using the IEEE-RTS. The RBTS is a small power system developed by Professor Roy Billinton, which is utilized extensively in reliability research work at the University of Saskatchewan. All the initial concept developments described in this thesis were done using the RBTS. These studies provide a useful framework for further development and educational activities in system well-being analysis.

A.2. Description of the Roy Billinton Test System (RBTS)

The Roy Billinton Test System is an educational test system developed at the University of Saskatchewan. The basic objective in designing the RBTS was to make it sufficiently small to permit a large number of reliability studies with reasonable solution time but sufficiently detailed to reflect the actual complexities involved in practical reliability analysis.

The single line diagram of this system is shown in Figure A.1. The system has 6 buses, 9 transmission lines and 11 generating units, ranging from 5 MW to 40 MW. The annual system peak load is 185 MW and the total installed generating capacity is 240 MW. The generation data for the RBTS are given in Table A.1. Additional data are given in Appendix B. The results presented utilize the main concepts developed and illustrated in the previous chapters.

Table A.1: Generating Unit Data of the RBTS.

Priority loading order	Unit size [MW]	RR	Cost parameters			Failure rate [f/yr]	Bus
			A	B	C		
1	40	8	0	0.5	0	3	2
2-3	20	4	0	0.5	0	2.4	2
4	40	2	26	12	0.01	6	1
5	40	2	28	12	0.01	6	1
6	20	1	16	12.25	0.02	5	1
7	10	1	14	12.5	0.02	4	1
8-9	20	4	0	0.5	0	2.4	2
10-11	5	1	0	0.5	0	2	2

RR= Response Rate in MW/min.

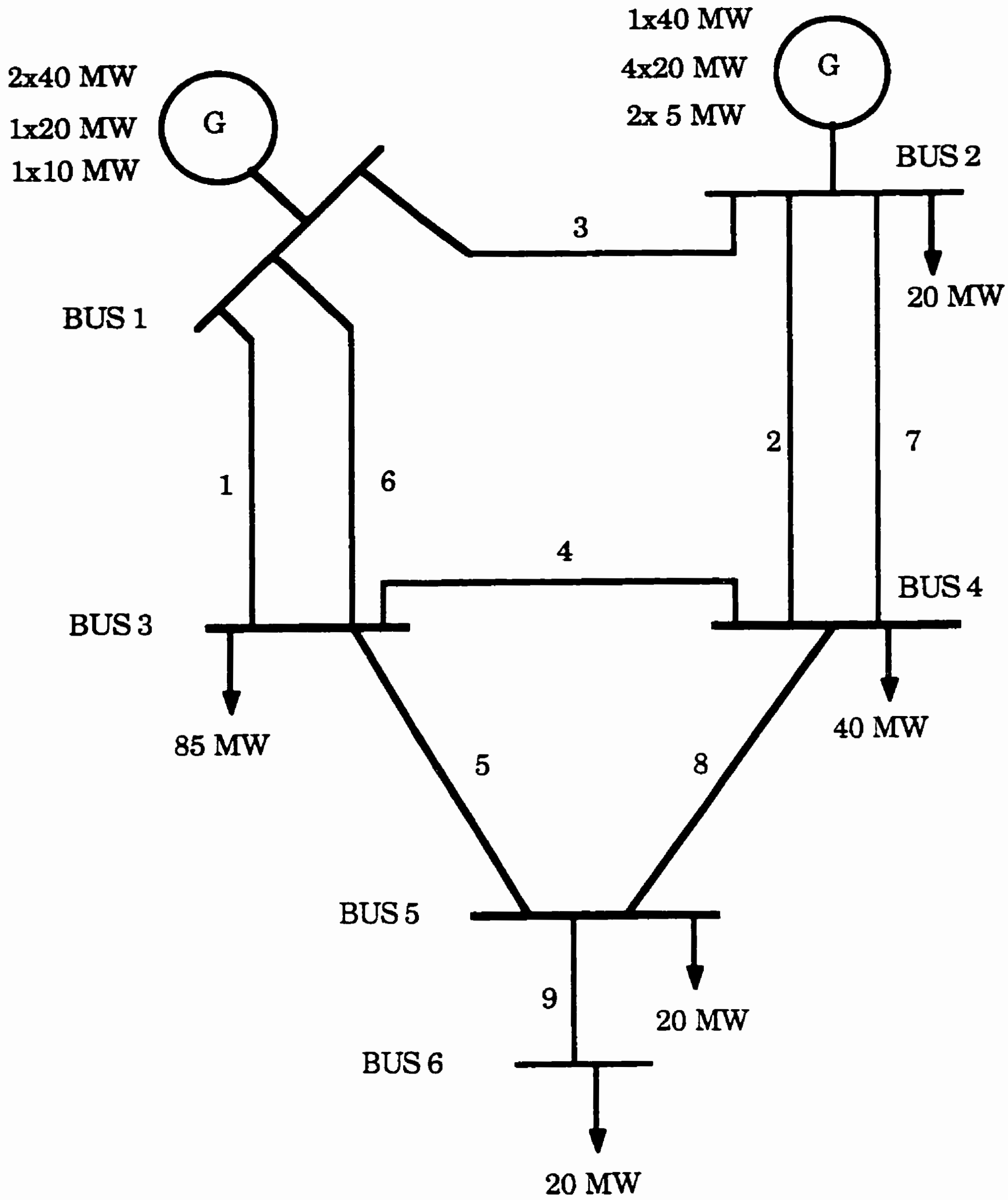

Figure A.1: Single line diagram of the RBTS.

A.3 Hierarchical Level I Unit Commitment Health Analysis

Once a unit commitment criterion is adopted, the goal is to satisfy the criterion throughout the various stages of system operation. A unit commitment schedule has been developed using a seven step load model of the RBTS assuming that the system lead time is four hours. Table A.2 shows the required number of committed units and the corresponding probabilities of the different operating states when a specified risk of 0.01 is selected as the unit commitment criterion. It can be seen from Table A.1, that the probability of the healthy state is zero for all load levels. The reason for this is that the system with the designated number of committed units and at the corresponding load level does not have sufficient spinning reserve to tolerate any single unit outage [156,157].

Table A.3 shows the number of committed units and system operating state probabilities when the system is required to satisfy an acceptable healthy state probability of 0.9 in addition to satisfying a specified risk of 0.01. It can be seen from Table A.3, that the system must commit one or two units, in addition to the previously committed units, to satisfy the multiple criteria.

Table A.2: Unit commitment in the RBTS for a single criterion.

load [MW]	spinning reserve	no. of units	Probability of Health	Margin	Risk
74	6	3	0	0.9964425	0.0035575
92	28	4	0	0.9958930	0.0041070
111	9	4	0	0.9937126	0.0062874
129	31	5	0	0.9931645	0.0068355
148	12	5	0	0.9909901	0.0090099
166	24	7	0	0.9931514	0.0068486
185	25	8	0	0.9931446	0.0068554

Table A.3: Unit commitment in the RBTS for multiple criteria.

load [MW]	spinning reserve	no. of units	Probability of		
			Health	Margin	Risk
74	46	4	0.9937125	0.0062747	0.0000128
92	68	5	0.9931645	0.0068205	0.0000150
111	49	5	0.9909901	0.0089800	0.0000299
129	51	6	0.9887275	0.0112270	0.0000455
148	42	7	0.9869216	0.0130205	0.0000579
166	44	8	0.9858401	0.0140946	0.0000653
185	45	9	0.9847597	0.0151675	0.0000728

In the results presented in Tables A.2 and A.3, it was assumed that the reserve in the system is only spinning reserve. Rapid start units can also be considered as part of the operating reserve in order to decrease the required spinning reserve. The RBTS has a number of gas turbine units with a capacity of 10 MW [154]. The rapid start units are assumed to be available within a lead time of 10 minutes. Tables A.4 and A.5 shows the required number of committed units and the system well-being indices considering that the system has two 10 MW rapid start units in addition to the on line committed units. Comparing the results shown in Table A.4 with those shown in Table A.2, it can be seen that the required number of committed units decreases with the inclusion of rapid start units. The number of committed units shown in Table A.5 are identical to those in Table A.3 even with the inclusion of rapid start units. The reason for this is that rapid start units cannot transfer the system to the healthy state if it is initially operating in the marginal state [61].

Some utilities consider interruptible load as a part of the operating reserve. Tables A.6 and A.7 show the results assuming that 10% of the system load can be interrupted within an interruption time of 5 minutes. The

Table A.4: Unit commitment in the RBTS including rapid start units (single criterion).

load [MW]	no. of units	Probability of		
		Health	Margin	Risk
74	3	0.00000408	0.99758430	0.00241162
92	4	0.00000881	0.99802974	0.00196145
111	4	0.00000718	0.99484792	0.00514490
129	5	0.00004156	0.9992024	0.00075604
148	5	0.0000175	0.99291487	0.00706763
166	6	0.00004462	0.99264149	0.00731389
185	7	0.00005140	0.99080053	0.00914807

Table A.5: Unit commitment in the RBTS including rapid start units (multiple criteria).

load [MW]	no. of units	Probability of		
		Health	Margin	Risk
74	4	0.99371747	0.00627473	0.0000078
92	5	0.99317266	0.00682056	0.00000677
111	5	0.99099820	0.00898008	0.00002172
129	6	0.98875557	0.01122733	0.00001710
148	7	0.98694954	0.01302086	0.00002960
166	8	0.98587196	0.01409506	0.00003298
185	9	0.98479555	0.01516809	0.00003636

Table A.6: Unit commitment in the RBTS including interruptible load (single criterion).

load [MW]	no. of units	Int. load [MW]	Probability of		
			Health	Margin	Risk
74	3	7.4	0	0.99644254	0.00355746
92	4	9.2	0	0.99589297	0.00410703
111	4	11.1	0.00001342	0.99583389	0.00415269
129	5	13	0.00004554	0.99978185	0.00017261
148	5	15	0.00001918	0.99309966	0.00688116
166	6	16.6	0.00004891	0.99301741	0.00693368
185	7	18.5	0.00007976	0.99294043	0.00697981

Table A.7: Unit commitment in the RBTS including interruptible load (multiple criteria).

load [MW]	no. of units	Int. load [MW]	Probability of		
			Health	Margin	Risk
74	4	7.4	0.99371256	0.0062747	0.00001274
92	5	9.5	0.99316449	0.00682051	0.000015
111	5	11.1	0.99100485	0.00898014	0.00001501
129	6	13	0.9887576	0.01122735	0.00001505
148	7	15	0.98693387	0.01302065	0.00004547
166	8	16.6	0.98588953	0.01409531	0.00001516
185	9	18.5	0.98481637	0.01516841	0.00001522

single and multiple operating criteria are identical to those for Tables A.2 and A.3.

A.4 Response Health Analysis

Assessment of unit commitment does not consider how the system spinning reserve must be allocated among the committed units in order to provide the minimum operating cost at an acceptable level of response reliability. Consider that unit commitment is done for the RBTS at a load level of 60% of the peak load of 185 MW, i.e. 111 MW, to satisfy the multiple criteria. The number of committed units is 5 and the total system spinning reserve is 49 MW. The system with this number of committed units has a high healthy state probability based on a unit commitment point of view as shown in Table A.3. It may or may not be in the healthy state in terms of system responding capability as this is extremely dependent on how the spinning reserve is distributed among the committed units. Only 20 MW of the total 49 MW of spinning reserve is available within a margin time of 5 minutes based on the economic load dispatch, which has the lowest operating cost of \$470.8. The generating units are reloaded to provide more response capability using the procedure described in Chapter 3. The variation in power outputs of the committed units and the total operating cost versus the system response are shown in Figure A.2. A discrete load change of 1 MW was used to obtain the loading schedules. The response capability, therefore, changes with each 1 MW step.

Figure A.2 has been divided into three different ranges assuming that the required regulating margin (RRM) is 50% of the spinning reserve (SR), i.e. 24 MW. Starting from an economic load dispatch, the unit loadings are adjusted by moving in the direction required to satisfy the response criterion. The response criterion could be a specified response risk, a specified response healthy state probability or both as described in Chapter 3. The lower range of unit power outputs represents the results where the response output varies from 20 to 24 MW and the system is in the risk state from response point of view. If a specified response risk of 0.001 is selected as the operating criterion, then the system should have at least 25 MW of response output to satisfy this criterion. A vertical line at a response output of 25 MW in Figure A.2 shows the optimum load dispatch for this condition .In this case, the operating cost increases from \$470.8 to \$529.98 and the response risk probability decreases from 1.0 to 0.00018834. All different load dispatches on the right hand side of this line meet the response criterion but this point has the cheapest cost. The second vertical line is the optimum load dispatch if the system is required to satisfy a specified response healthy state probability of 0.9 in addition to satisfying an acceptable response risk of 0.001. At this load dispatch, the total response output is 41 MW and the system operating cost is \$721. The response health probability is 0.99981166 with this response output.

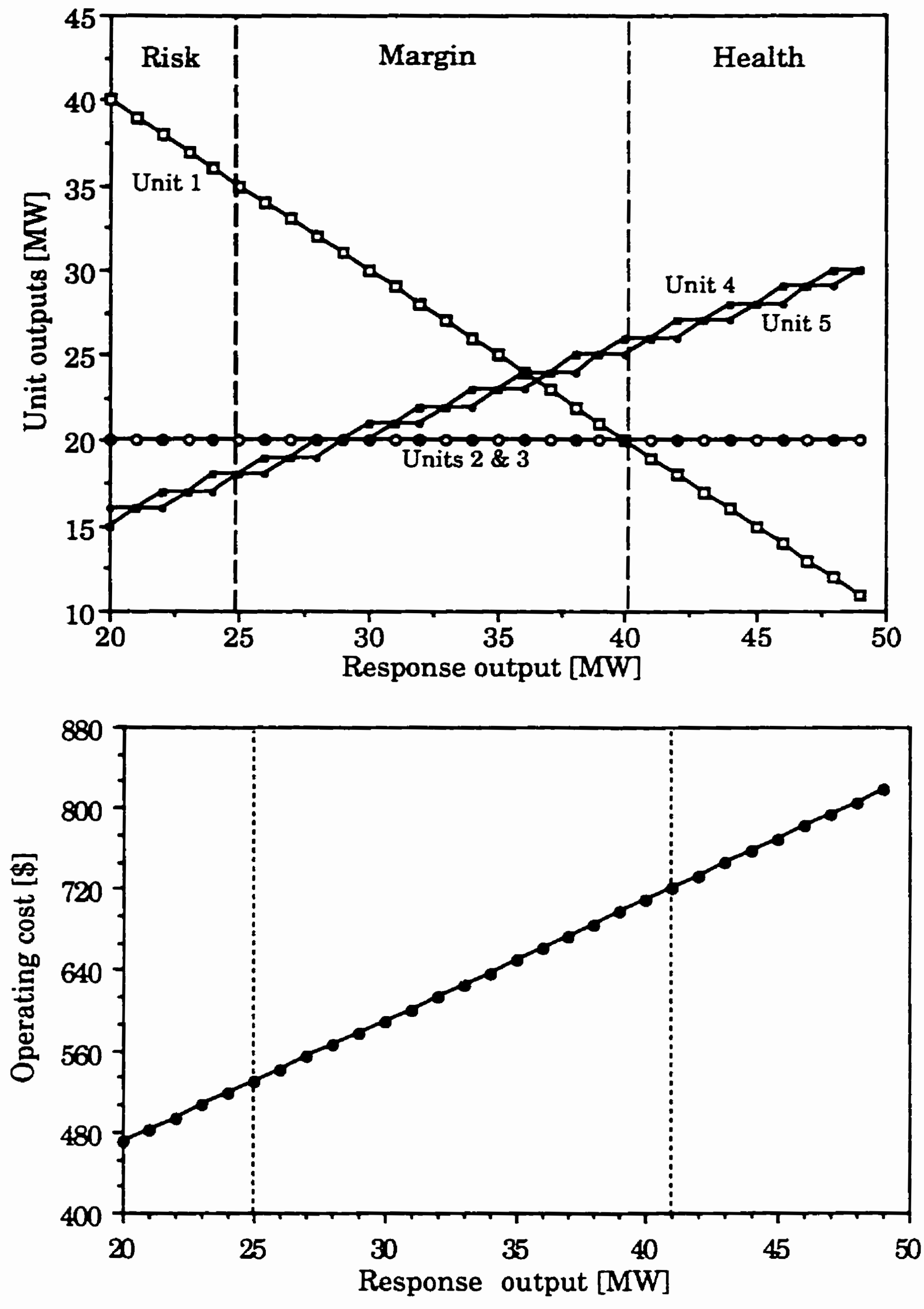

Figure A.2. Unit power outputs and operating costs versus response.

Table A.8 shows the economic load dispatch for a seven step load model of the RBTS. The number of committed units are such that the system can satisfy multiple unit commitment criteria as shown in Table A.3. The response health, margin and risk probabilities are calculated assuming that the required regulating margin is 50% of the spinning reserve at each load level and the margin time is 5 minutes. The response risk is unity for some load levels, because of insufficient response capability. Table A.9 shows the results when a specified response risk of 0.001 is selected as the response criterion. The results show that the response healthy state probability is zero for all load levels. The reason for this is that the system with the available response output within the margin time of 5 minutes and at the corresponding load level cannot respond to a specific single unit outage. Table A.10 shows the results when the system is required to satisfy an acceptable response healthy state probability of 0.95 in addition to satisfying a specified response risk of 0.001.

Table A.8: System response health, margin and risk probabilities for economic load dispatch.

load MW	SR MW	RRM MW	Cost $	Generating unit outputs U1	U2	U3	U4	U5	U6	U7	U8	U9	Response Health	Margin	Risk	RM MW
74	46	23	179	24	20	20	10						0	0.9998687	0.0001313	26
92	68	34	332	32	20	20	10	10					0	0	1.0	28
111	49	24	470.81	40	20	20	15	16					0	0	1.0	20
129	51	25	709.43	40	20	20	22	22	5				0	0	1.0	25
148	42	21	961.21	40	20	20	28	29	8	3			0	0.9997641	0.0002359	30
166	44	22	946.09	40	20	20	28	28	7	3	20		0	0.9997032	0.0002968	30
185	45	22	943.54	40	20	20	27	28	7	3	20	20	0	0.9996804	0.0003196	30

Table A.9: System response health, margin and risk probabilities for a single response criterion.

load MW	SR MW	RRM MW	Cost $	Generating unit outputs U1	U2	U3	U4	U5	U6	U7	U8	U9	Response Health	Margin	Risk	RM MW
74	46	23	179	24	20	20	10						0	0.9998687	0.0001313	26
92	68	34	414.15	25	20	20	14	13					0	0.9998117	0.0001883	35
111	49	24	529.98	35	20	20	18	18					0	0.9998117	0.0001883	25
129	51	25	721.38	39	20	20	23	22	5				0	0.9997641	0.0002359	26
148	42	21	961.21	40	20	20	28	29	8	3			0	0.9997641	0.0002359	30
166	44	22	946.09	40	20	20	28	28	7	3	20		0	0.9997032	0.0002968	30
185	45	22	943.54	40	20	20	27	28	7	3	20	20	0	0.9996804	0.0003196	30

Table A.10: System response health, margin and risk probabilities for multiple response criteria.

load MW	SR MW	RRM MW	Cost $	generating unit outputs U1	U2	U3	U4	U5	U6	U7	U8	U9	Response Health	Margin	Risk	RM MW
74	46	23	356.75	9	20	20	25						0.9998687	0	0.0001313	41
92	68	34	484.95	19	20	20	17	16					0.9998117	0	0.0001883	41
111	49	24	721.02	19	20	20	26	26					0.9998117	0	0.0001883	41
129	51	25	901.53	24	20	20	29	28	8				0.9997641	0.0000476	0.0001883	41
148	42	21	1094.9	29	20	20	30	30	14	5			0.9997261	0.0000856	0.0001883	41
166	44	22	1079.4	29	20	20	30	30	12	5	20		0.9997032	0.0000856	0.0002112	41
185	45	22	1076.7	29	20	20	30	30	11	5	20	20	0.9996804	0.0000856	0.0002340	41

The variation in the system operating cost of the three load dispatches is shown in Figure A.3. It can be seen that the system operating cost increases as the system is required to satisfy single or multiple response criteria compared to that of the economic load dispatch.

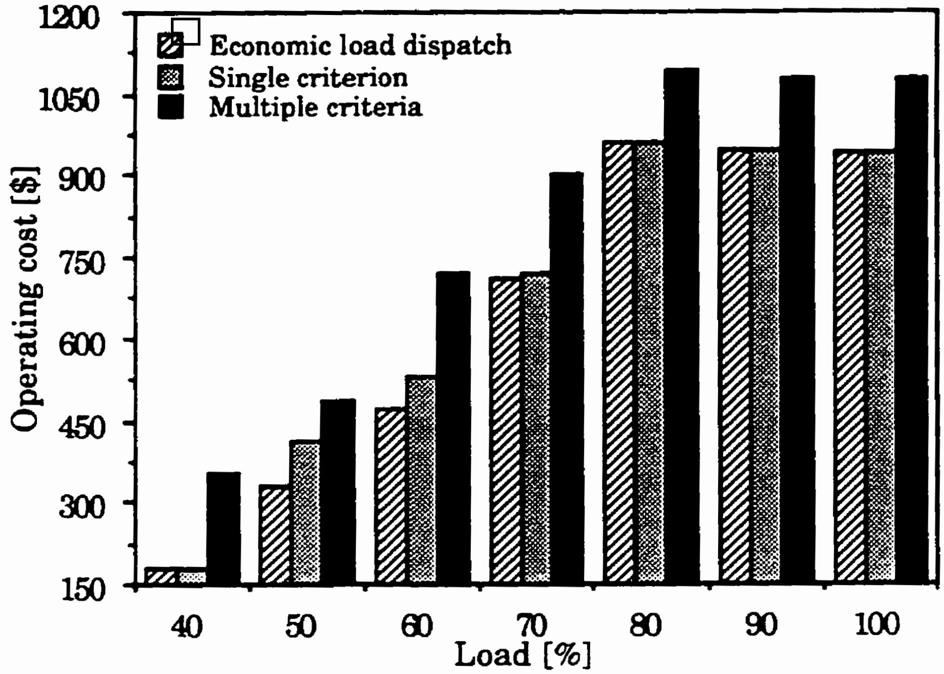

Figure A.3: Variation in system operating cost for different load dispatches.

The margin time is an important factor which influences the system well-being. The spinning reserve has been allocated among the on-line units such that multiple response criteria must be satisfied. The results are presented in Figure A.4 for three different margin times (MT). The system load of 185 MW is designated as the 100% load level. It can be seen from the results that for a given load level, the response healthy state probability decreases as the margin time increases .

Figure A.5 shows the variation in the system operating cost with system peak load. It can be seen that the operating cost increases as the peak load

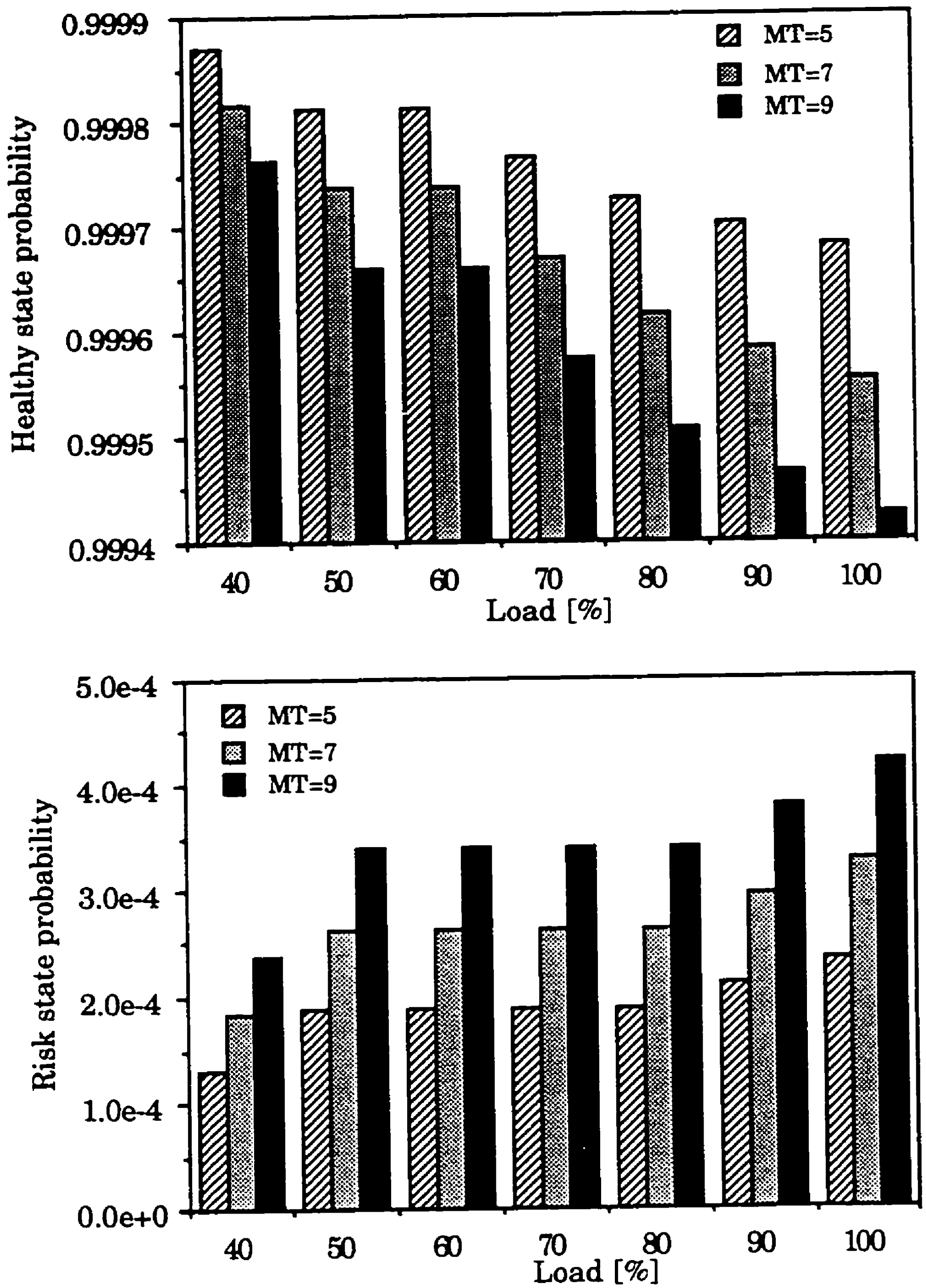

Figure A.4: Response health and risk state probabilities for various margin times.

increases. In comparison with the results shown in Figure A.4, it can be seen that for a given load level the operating cost increases as the response health probability increases.

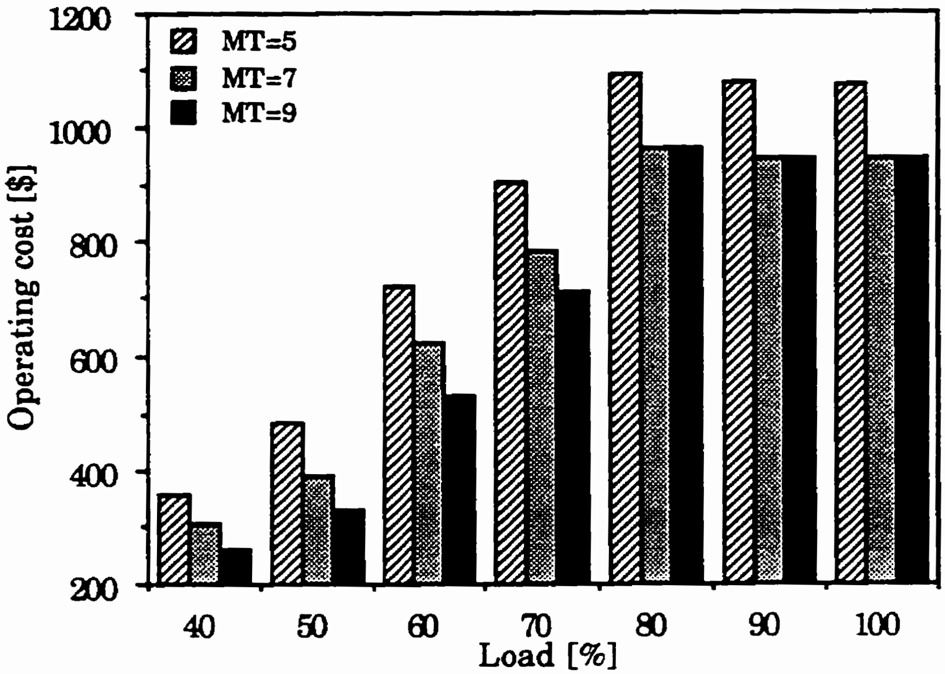

Figure A.5: Operating cost for various margin times.

Rapid start gas turbine units can pick up load in a relatively short period of time. These units, therefore, can participate in the response health, margin and risk constrained economic load dispatch provided that their lead time is less than the margin time. Table A.11 shows the economic load dispatch of the seven step load model using the number of committed units presented in Table A.4. The margin time in this study is considered to be 10 minutes. The results show that the system at the economic load dispatch can also satisfy a specified response risk of 0.001. This, however, is not the case without considering rapid start units. Table A.11 shows that this system can satisfy multiple response criteria only at the 129 MW load level. Table A.12 shows the economic load dispatch when the number of committed units are identical

Table A.11: System response health, margin and risk probabilities for economic load dispatch and a single response criterion considering rapid start units.

load MW	SR MW	RRM MW	Cost $	Generating unit outputs U1	U2	U3	U4	U5	U6	U7	Response Health	Margin	Risk	RM MW
74	6	3	37	34	20	20					0	0.99991054	0.00008946	22.1
92	28	14	211.44	40	20	20	12				0	0.99979640	0.00020360	36.1
111	9	4	447.61	40	20	20	31				0	0.99979640	0.00020360	25.1
129	31	15	694.01	40	20	20	24	25			0.96097618	0.03873493	0.00028889	47.1
148	12	6	933.12	40	20	20	34	34			0	0.99968226	0.00031774	28.1
166	14	7	1175.26	40	20	20	37	37	12		0	0.99964854	0.00035146	30.1
185	5	2	1431.24	40	20	20	40	40	16	9	0	0.99964559	0.00035441	21.1

Table A.12: System response health, margin and risk probabilities for economic load dispatch, single and multiple response criteria considering rapid start units.

load MW	SR MW	RRM MW	Cost $	Generating unit outputs U1	U2	U3	U4	U5	U6	U7	U8	U9	Response Health	Margin	Risk	RM MW
74	46	23	179	24	20	20	10						0.96108589	0.03881302	0.00010109	52.1
92	68	34	332	32	20	20	10	10					0.99968226	0.00017616	0.00014158	64.1
111	49	24	470.81	40	20	20	15	16					0.96097618	0.03880859	0.00021524	56.1
129	51	25	709.43	40	20	20	22	22	5				0.99967858	0.00022018	0.00010124	62.1
148	42	21	961.21	40	20	20	28	29	8	3			0.96092210	0.03878900	0.00028890	56.1
166	44	22	946.09	40	20	20	28	28	7	3	20		0.99962940	0.00007993	0.00029067	57.1
185	45	22	943.54	40	20	20	27	28	7	3	20	20	0.99961321	0.00009435	0.00029244	58.1

to those shown in Table A.5. It can be seen that the system at the economic load dispatch can satisfy both single and multiple response criteria if required.

In addition to the generating capacity, some utilities consider interruptible load as a part of the operating reserve. Interruptible load can increase the response capability of the system if the interruption time is less than or equal to the margin time. Table A.13 shows the economic load dispatch and the associated response well-being indices of the seven step load model of the RBTS considering that the system has the ability to interrupt 10% of the load at an interruption time of 5 minutes. The number of committed units are identical to those shown in Table A.6. It can be seen from the results that the system at the economic load dispatch can also satisfy a specified response risk of 0.001 if required. The system will have more response reserve if the 5 units at the 129 MW load level are reloaded to satisfy multiple criteria. In this case, the system operating cost increases from \$694.01 to \$790.25. Table A.14 shows the economic load dispatch when the number of committed units are identical to those shown in Table A.7. The system at the economic load dispatch can satisfy the single response risk criterion at all load levels. It can be seen by comparing Table A.8 with Table A.14, that the system can transfer to the healthy state by inclusion of interruptible load for the last three load levels and with the same operating cost.

Table A.15 shows the results in which multiple response criteria are satisfied at all load levels. Compared to the results shown in Table A.14 it can be seen that the system operating cost increases for some load levels with the provision of more response reserve.

Table A.13: System response health, margin and risk probabilities for economic load dispatch using the number of committed units shown in Table A.6.

load MW	Int. load MW	RRM MW	Cost $	Generating unit outputs U1	U2	U3	U4	U5	U6	U7	Response Health	Margin	Risk	RM MW
74	7.4	3	37	34	20	20					0	0.99992580	0.00007420	13.4
92	9.5	14	211.44	40	20	20	12				0	0.99986873	0.00013127	19.5
111	11.1	4	447.61	40	20	20	31				0	0.99986873	0.00013127	20.1
129	13	15	694.01	40	20	20	24	25			0	0.99981166	0.00018834	33
148	15	6	933.12	40	20	20	34	34			0	0.99985731	0.00014269	27
166	16.6	7	1175.26	40	20	20	37	37	12		0	0.99985731	0.00014269	27.6
185	18.5	2	1431.24	40	20	20	40	40	16	9	0	0.99985731	0.00014269	23.5

Table A.14: System response health, margin and risk probabilities for economic load dispatch using the number of committed units shown in Table A.7.

load MW	Int. load MW	RRM MW	Cost $	Generating unit outputs U1	U2	U3	U4	U5	U6	U7	U8	U9	Response Health	Margin	Risk	RM MW
74	7.4	23	179	24	20	20	10						0	0.99986873	0.00013127	33.4
92	9.5	34	332	32	20	20	10	10					0	0.99981166	0.00018834	37.5
111	11.1	24	470.81	40	20	20	15	16					0	0.99981166	0.00018834	31.1
129	13	25	709.43	40	20	20	22	22	5				0	0.99981166	0.00018834	38
148	15	21	961.21	40	20	20	28	29	8	3			0.99972606	0.00013125	0.00014269	45
166	16.6	22	946.09	40	20	20	28	28	7	3	20		0.99970323	0.00015407	0.00014269	46.6
185	18.5	22	943.54	40	20	20	27	28	7	3	20	20	0.99971845	0.00013885	0.00014270	48.5

Table A.15: System response health, margin and risk probabilities for load dispatch with multiple response criteria using the number of committed units shown in Table A.7.

load	Int. load	RRM	Cost	Generating unit outputs									Response			RM
MW	MW	MW	$	U1	U2	U3	U4	U5	U6	U7	U8	U9	Health	Margin	Risk	MW
74	7.4	23	261.39	17	20	20	17						0.99986873	0	0.00013127	40.4
92	9.5	34	367.15	29	20	20	12	11					0.99981166	0	0.00018834	40.5
111	11.1	24	577.5	31	20	20	20	20					0.99981160	0	0.0001883	40.1
129	13	25	745.3	37	20	20	24	23	5				0.99976410	0.00004756	0.00018834	41
148	15	21	961.21	40	20	20	28	29	8	3			0.99972606	0.00013125	0.00014269	45
166	16.6	22	946.09	40	20	20	28	28	7	3	20		0.99970323	0.00015407	0.00014269	46.6
185	18.5	22	943.54	40	20	20	27	28	7	3	20	20	0.99971845	0.00013885	0.00014270	48.5

A.5 Unit Commitment in the Two Interconnected Roy Billinton Test Systems

Unit commitment in the two interconnected RBTS has been done using the technique presented in Chapter 5. The two systems are interconnected through a tie line of capacity of 30 MW with a failure rate of one failure per year. The lead time associated with the two systems is assumed to be 4 hours. Table A.16 shows the required number of committed units and the overall interconnected system indices when two identical RBTS are interconnected. Compared to the results shown in Tables A.2 and A.3, it can be seen that the two systems can operate in the healthy state with lower spinning reserve by virtue of interconnection. Table A.17 shows the results when System X has a constant load of 111 MW and the load in System Y varies from 40% to 100% of the system peak load of 185 MW. From the results it can be seen that System Y should commit more units at some load levels compared to those shown in Table A.16. The reason for this is that at these load levels the assistance provided by System X to Y is less than that provided in the case shown in Table A.16.

Table A.16: Unit commitment and operating state probabilities of the two identical interconnected RBTS.

Peak load		No. of units		Spin. res.		Overall interconnected system indices		
X	Y	X	Y	X	Y	Health	Margin	Risk
74	74	4	4	46	46	0.99587169	0.00412448	0.00000383
92	92	4	4	28	28	0.98697832	0.01298112	0.00004056
111	111	5	5	49	49	0.99312982	0.00685499	0.00001519
129	129	5	5	31	31	0.98588212	0.01405278	0.00006510
148	148	6	5	32	12	0.97931564	0.02055809	0.00012627
166	166	7	7	24	24	0.97349787	0.02635158	0.00015055
185	185	8	8	25	25	0.97135949	0.02847510	0.00016541

Table A.17: Impact of load variation on the unit commitment and operating state probabilities in the two interconnected RBTS.

Peak load		No. of units		Spin. res.		Overall interconnected system indices		
X	Y	X	Y	X	Y	Health	Margin	Risk
111	74	5	4	49	46	0.99313582	0.00684903	0.00001515
111	92	5	4	49	28	0.98643244	0.01352474	0.00004282
111	111	5	5	49	49	0.99312982	0.00685499	0.00001519
111	129	5	6	49	51	0.99312981	0.00685500	0.00001519
111	148	5	6	49	32	0.99262584	0.00735550	0.00001867
111	166	5	8	49	44	0.99312980	0.00685474	0.00001546
111	185	5	9	49	45	0.99312978	0.00685466	0.00001556

A.6 Composite System Health Analysis

The results presented in Sections A.3 to A.4 deal with operating reserve evaluation at HLI. Unit commitment health analysis in an interconnected generating system was presented in Section A.5 as the first step in the application of composite system evaluation in which the tie-line constraints are taken into account. Unit commitment health analysis in composite generation and transmission systems is presented in this section using the technique proposed in Chapter 7. The 6-bus RBTS [154] has been modified to a 5 bus system having 8 lines by connecting the load of Bus 6 plus the base case power flow loss of line 9 at Bus 5 as shown in Figure A.6. This modification was done to remove the radial line between Buses 5 and 6, as the probability of the healthy state will be always zero because the outage of Line 9 (single level contingency) will isolate Bus 6 and result in the curtailment of 20 MW of load at Bus 6.

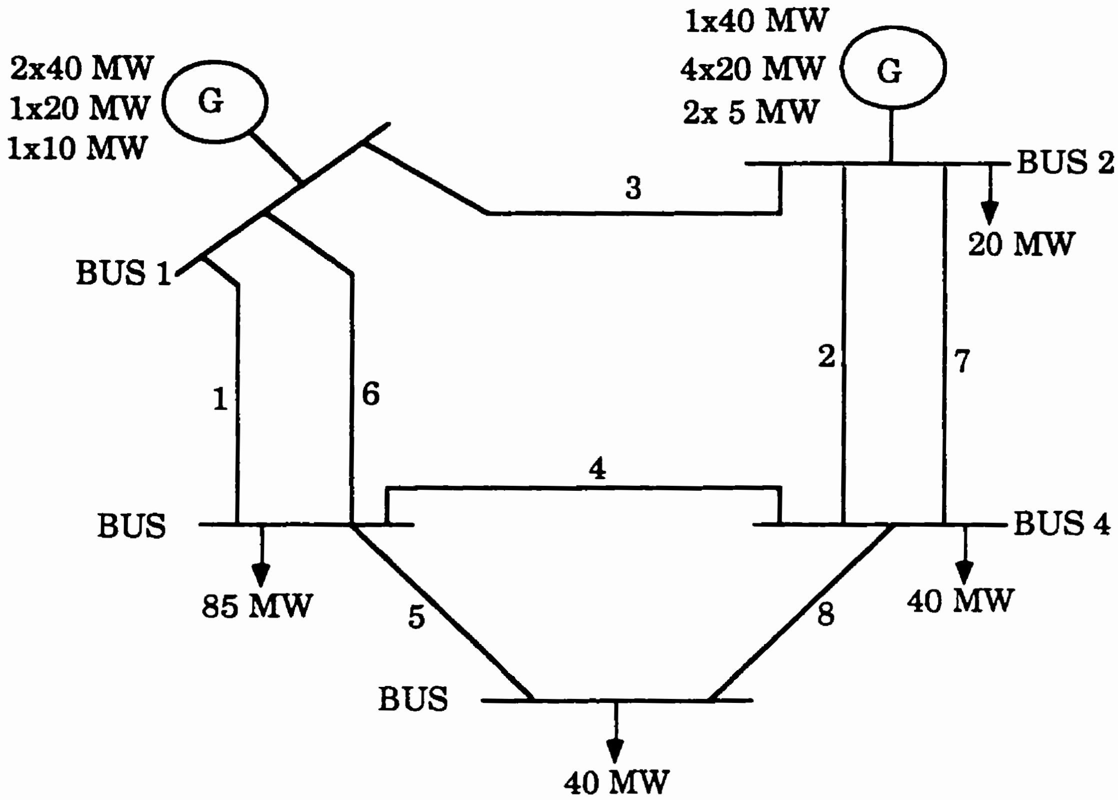

Figure A.6: Modified RBTS (MRBTS).

Table A.18 shows the composite system well-being indices using the number of committed units in Table A.2. It can be seen that the system can satisfy the single risk criterion at both HLI and HLII. Compared to the results shown in Table A.2, it can be seen that the HLII system risk increases. The reason for this is that the line flow and voltage constraints are added to the already considered active power constraint at HLI. Table A.19 shows the results when the system is required to satisfy multiple criteria at HLII. The number of committed units are identical to those shown in Table A.3 where multiple criteria are satisfied at HLI. Comparing Tables A.3 and A.19, it can be seen that the system healthy state probability decreases at HLII compared to that of HLI.

Table A.18: HLII unit commitment in the MRBTS for a single criterion.

load [MW]	spinning reserve	no. of units	Probability of		
			Health	Margin	Risk
74	6	3	0	0.99643132	0.00356868
92	28	4	0	0.99583680	0.00416320
111	9	4	0	0.99369244	0.00630756
129	31	5	0	0.99314284	0.00685716
148	12	5	0	0.99096379	0.00903621
166	24	7	0	0.99306498	0.00693502
185	25	8	0	0.99130960	0.00869040

Table A.19: HLII unit commitment in the MRBTS for multiple criteria.

load [MW]	spinning reserve	no. of units	Probability of		
			Health	Margin	Risk
74	46	4	0.99131772	0.00866799	0.00001430
92	68	5	0.99073369	0.00924971	0.00001661
111	49	5	0.98743102	0.01253596	0.00003302
129	51	6	0.98517042	0.0147809	0.00004868
148	42	7	0.98448287	0.01545214	0.00006499
166	44	8	0.96463828	0.03515405	0.00020767
185	45	9	0.96357824	0.03620258	0.00021917

System lead time is an important factor influencing the system well-being indices. The required amount of spinning reserve usually increases as the system lead time is increased. In order to illustrate the impact of system lead time on the well-being indices, a study was conducted in which the number of committed units was fixed at 5 for a load of 60% (111 MW) of the peak load of 185 MW in the RBTS . The total spinning capacity is 160 MW and the system lead time varies from 1 to 15 hours. The results are presented in Figures A.7 and A.8. It can be seen from these figures that as the lead time increases, the probability of the healthy state decreases. The probability of the healthy state

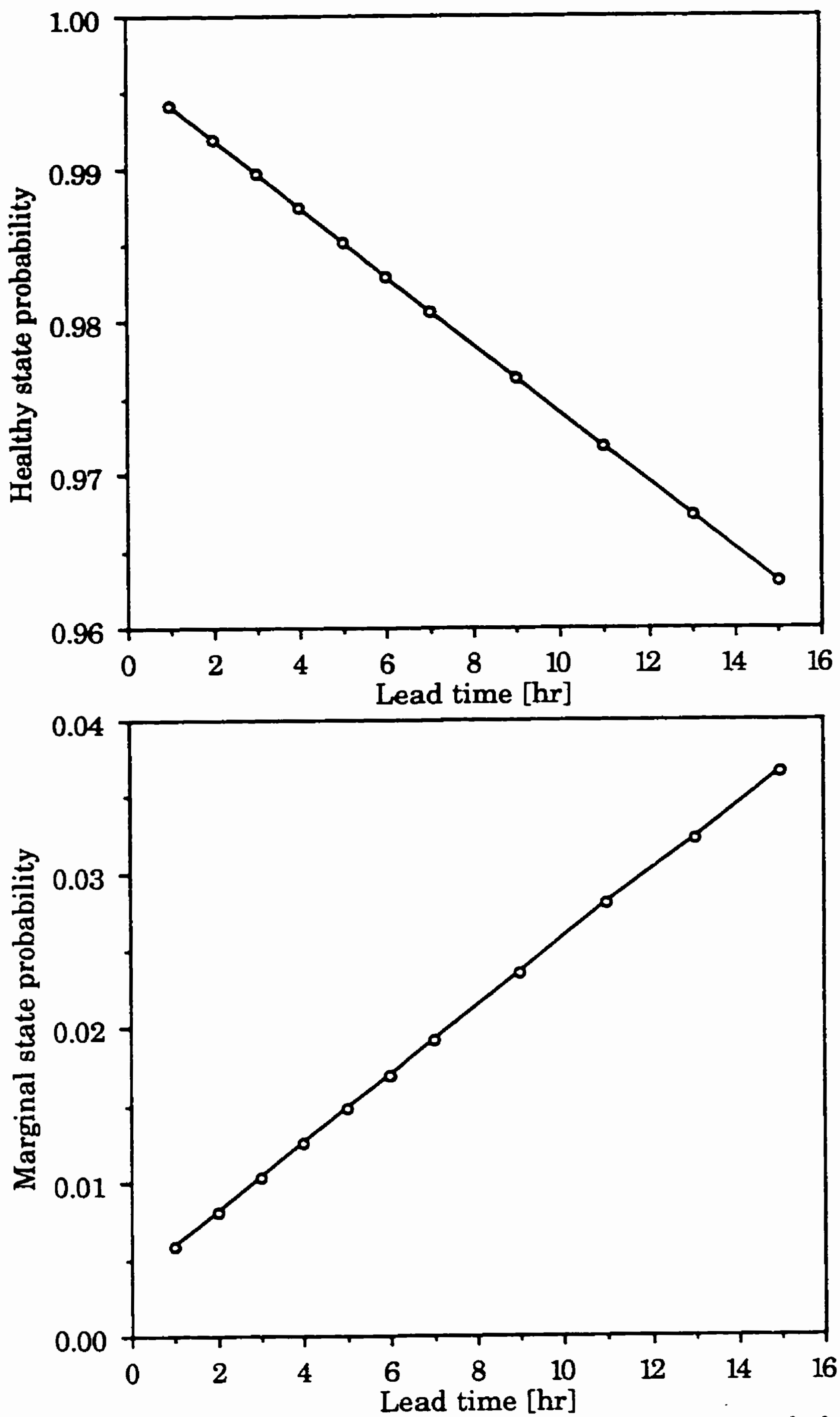

Figure A.7: Variation of system healthy and marginal state probabilities versus lead time - MRBTS.

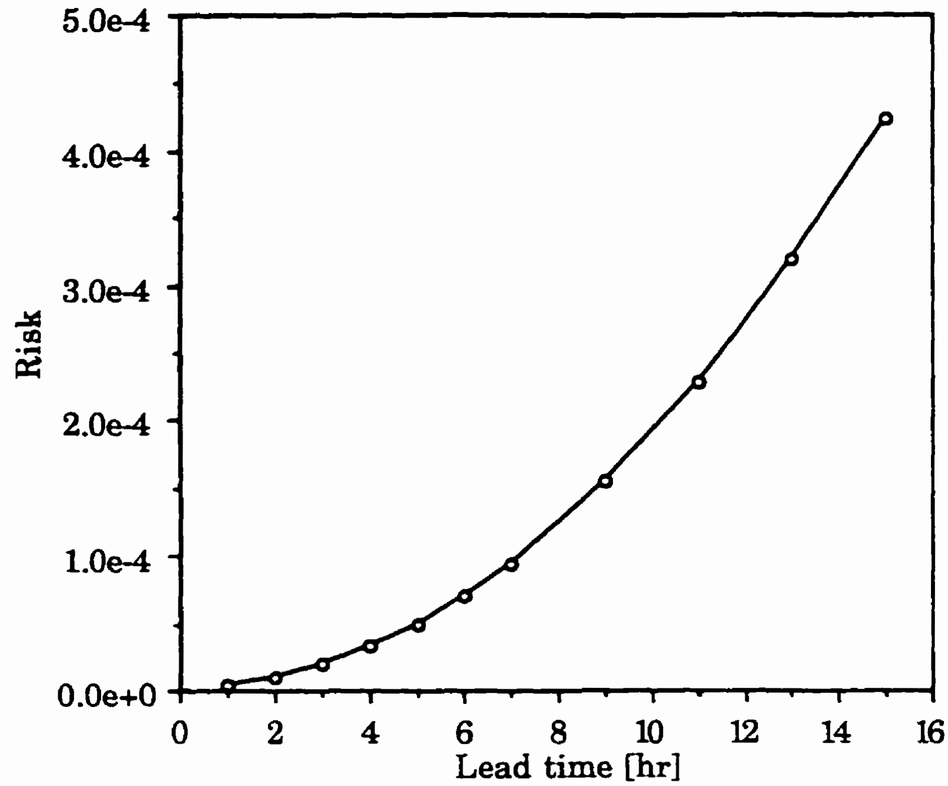

Figure A.8: Variation of system risk versus lead time - MRBTS.

decreases from 0.99417694 to 0.96299462 when the system lead time is increased from 1 hour to 15 hours. The probabilities of the marginal and risk states increase as the lead time is increased.

A.7 Conclusions

Reliability test systems provide useful references for testing and comparing alternate techniques for power system reliability evaluation. The techniques based on utilizing the system well-being framework in operating reserve assessment are illustrated in this appendix by application to the RBTS. Most of the studies conducted are similar to those performed on the IEEE-RTS and described in the previous chapters. Utilization of the RBTS provides the opportunity to conduct a large number of studies with low computation time. Unit commitment in this system was conducted considering stand-by units and interruptible load. The effects of these factors on the response well-being and the operating cost are illustrated. Unit commitment in composite generation and transmission system was also conducted using the modified RBTS. The impact on the HLII system well-being indices of variations in the system lead time is also illustrated by application to the RBTS. The studies conducted on the RBTS proved invaluable in the development of a physical appreciation of the factors that affect system well-being.

B. DATA OF THE 6 BUS RBTS

Table B.1: Bus data.

Bus No.	Load (p.u)		P_g	Q_{max}	Q_{min}	V_0	V_{max}	V_{min}
	Active	Reactive						
1	0.00	0.0	1.0	0.50	-0.40	1.05	1.05	0.97
2	0.20	0.0	1.2	0.75	-0.40	1.05	1.05	0.97
3	0.85	0.0	0.0	0.00	0.00	1.00	1.05	0.97
4	0.40	0.0	0.0	0.00	0.00	1.00	1.05	0.97
5	0.20	0.0	0.0	0.00	0.00	1.00	1.05	0.97
6	0.20	0.0	0.0	0.00	0.00	1.00	1.05	0.97

Table B.2: Line data.

Line No.	Bus		R	X	B/2	Tap	Current Rating [p.u]	Failure Rate [occ/yr]	Repair Time [hr]
	I	J							
1	1	3	0.0342	0.18	0.0106	1.00	0.85	1.50	10.0
2	2	4	0.1140	0.60	0.0352	1.00	0.71	5.00	10.0
3	1	2	0.0912	0.48	0.0282	1.00	0.71	4.00	10.0
4	3	4	0.0228	0.12	0.0071	1.00	0.71	1.00	10.0
5	3	5	0.0228	0.12	0.0071	1.00	0.71	1.00	10.0
6	1	3	0.0342	0.18	0.0106	1.00	0.85	1.50	10.0
7	2	4	0.1140	0.60	0.0352	1.00	0.71	5.00	10.0
8	4	5	0.0228	0.12	0.0071	1.00	0.71	1.00	10.0
9	5	6	0.0228	0.12	0.0071	1.00	0.71	1.00	10.0

Table B.3: Generator data.

Unit No.	Bus No.	Rating [MW]	Failure Rate [occ/yr]	Repair Time (hrs)
1	1	40.0	6.00	45.0
2	1	40.0	6.00	45.0
3	1	10.0	4.00	45.0
4	1	20.0	5.00	45.0
5	2	5.0	2.00	45.0
6	2	5.0	2.00	45.0
7	2	40.0	3.00	60.0
8	2	20.0	2.40	55.0
9	2	20.0	2.40	55.0
10	2	20.0	2.40	55.0
11	2	20.0	2.40	55.0

C. DATA OF THE IEEE-RTS

Table C.1: Bus data.

Bus No.	load(p.u) Active	Reactive	P_g	Q_{max}	Q_{min}	V_0	V_{max}	V_{min}
1	1.080	0.220	1.720	1.20	-0.75	1.00	1.05	0.95
2	0.970	0.200	1.720	1.20	-0.75	1.00	1.05	0.95
3	1.800	0.370	0.000	0.00	0.00	1.00	1.05	0.95
4	0.740	0.150	0.000	0.00	0.00	1.00	1.05	0.95
5	0.710	0.140	0.000	0.00	0.00	1.00	1.05	0.95
6	1.360	0.280	0.000	0.00	0.00	1.00	1.05	0.95
7	1.250	0.250	3.000	2.70	0.00	1.00	1.05	0.95
8	1.710	0.350	0.000	0.00	0.00	1.00	1.05	0.95
9	1.750	0.360	0.000	0.00	0.00	1.00	1.05	0.95
10	1.950	0.400	0.000	0.00	0.00	1.00	1.05	0.95
11	0.000	0.000	0.000	0.00	0.00	1.00	1.05	0.95
12	0.000	0.000	0.000	0.00	0.00	1.00	1.05	0.95
13	2.650	0.540	5.500	3.60	0.00	1.00	1.05	0.95
14	1.940	0.390	0.000	3.00	-0.75	1.00	1.05	0.95
15	3.170	0.640	2.100	1.65	-0.75	1.00	1.05	0.95
16	1.000	0.200	1.450	1.20	-0.75	1.00	1.05	0.95
17	0.000	0.000	0.000	0.00	0.00	1.00	1.05	0.95
18	3.330	0.680	4.000	3.00	-0.75	1.00	1.05	0.95
19	1.810	0.370	0.000	0.00	0.00	1.00	1.05	0.95
20	1.280	0.260	0.000	0.00	0.00	1.00	1.05	0.95
21	0.000	0.000	3.500	3.00	-0.75	1.00	1.05	0.95
22	0.000	0.000	2.500	1.45	-0.90	1.00	1.05	0.95
23	0.000	0.000	6.600	4.50	-1.75	1.00	1.05	0.95
24	0.000	0.000	0.000	0.00	0.00	1.00	1.05	0.95

Table C.2: Line data.

Line No.	Bus		R	X	B/2	Tap	Current Rating [p.u]	Failure Rate [occ/yr]	Repair Time [hr]
	I	J							
1	1	2	0.026	0.0139	0.2306	1.00	1.93	0.240	16.0
2	1	3	0.0546	0.2112	0.0286	1.00	2.08	0.510	10.0
3	1	5	0.0218	0.0845	0.0115	1.00	2.08	0.330	10.0
4	2	4	0.0328	0.1267	0.0172	1.00	2.08	0.390	10.0
5	2	6	0.0497	0.1920	0.0260	1.00	2.08	0.390	10.0
6	3	9	0.0308	0.1190	0.0161	1.00	2.08	0.480	10.0
7	3	24	0.0023	0.0839	0.0000	1.00	5.10	0.020	768.0
8	4	9	0.0268	0.1037	0.0141	1.00	2.08	0.360	10.0
9	5	10	0.0228	0.0883	0.0120	1.00	2.08	0.340	10.0
10	6	10	0.0139	0.0605	1.2295	1.00	1.93	0.330	35.0
11	7	8	0.0159	0.0614	0.0166	1.00	2.08	0.300	10.0
12	8	9	0.0427	0.1651	0.0224	1.00	2.08	0.440	10.0
13	8	10	0.0427	0.1651	0.0224	1.00	2.08	0.440	10.0
14	9	11	0.0023	0.0839	0.0000	1.00	6.00	0.020	768.0
15	9	12	0.0023	0.0839	0.0000	1.00	6.00	0.020	768.0
16	10	11	0.0023	0.0839	0.0000	1.00	6.00	0.020	768.0
17	10	12	0.0023	0.0839	0.0000	1.00	6.00	0.020	768.0
18	11	13	0.0061	0.0476	0.0500	1.00	6.00	0.020	768.0
19	11	14	0.0054	0.0418	0.0440	1.00	6.00	0.390	11.0
20	12	13	0.0061	0.0476	0.0500	1.00	6.00	0.400	11.0
21	12	23	0.0124	0.0966	0.1015	1.00	6.00	0.520	11.0
22	13	23	0.0111	0.0865	0.0909	1.00	6.00	0.490	11.0
23	14	16	0.0050	0.0389	0.0409	1.00	6.00	0.380	11.0
24	15	16	0.0022	0.0173	0.0364	1.00	6.00	0.330	11.0
25	15	21	0.0063	0.0490	0.0515	1.00	6.00	0.410	11.0
26	15	21	0.0063	0.0490	0.0515	1.00	6.00	0.410	11.0
27	15	24	0.0067	0.0519	0.0546	1.00	6.00	0.410	11.0
28	16	17	0.0033	0.0259	0.0273	1.00	6.00	0.350	11.0
29	16	19	0.0030	0.0231	0.0243	1.00	6.00	0.340	11.0
30	17	18	0.0018	0.0144	0.0152	1.00	6.00	0.320	11.0
31	17	22	0.0135	0.1053	0.1106	1.00	6.00	0.540	11.0
32	18	21	0.0033	0.0259	0.0273	1.00	6.00	0.350	11.0
33	18	21	0.0033	0.0259	0.0273	1.00	6.00	0.350	11.0
34	19	20	0.0051	0.0396	0.0417	1.00	6.00	0.380	11.0
35	19	20	0.0051	0.0396	0.0417	1.00	6.00	0.380	11.0
36	20	23	0.0028	0.0216	0.0228	1.00	6.00	0.340	11.0
37	20	23	0.0028	0.0216	0.0228	1.00	6.00	0.340	11.0
38	21	22	0.0087	0.0678	0.0712	1.00	6.00	0.450	11.0

Table C.3: Generator data.

Unit No.	Bus No.	Rating [MW]	Failures per year	Repair time [hr]
1	22	50.0	4.420	20.0
2	22	50.0	4.420	20.0
3	22	50.0	4.420	20.0
4	22	50.0	4.420	20.0
5	22	50.0	4.420	20.0
6	22	50.0	4.420	20.0
7	15	12.0	2.980	60.0
8	15	12.0	2.980	60.0
9	15	12.0	2.980	60.0
10	15	12.0	2.980	60.0
11	15	12.0	2.980	60.0
12	15	155.0	9.130	40.0
13	7	100.0	7.300	50.0
14	7	100.0	7.300	50.0
15	7	100.0	7.300	50.0
16	13	197.0	9.220	50.0
17	13	197.0	9.220	50.0
18	13	197.0	9.220	50.0
19	1	20.0	19.47	50.0
20	1	20.0	19.47	50.0
21	1	76.0	4.470	40.0
22	1	76.0	4.470	40.0
23	2	20.0	19.47	50.0
24	2	20.0	19.47	50.0
25	2	76.0	4.470	40.0
26	2	76.0	4.470	40.0
27	23	155.0	9.130	40.0
28	23	155.0	9.130	40.0
29	23	350.0	7.620	100.0
30	18	400.0	7.960	150.0
31	21	400.0	7.960	150.0
32	16	155.0	9.130	40.0

D: RAPID START AND HOT RESERVE UNIT DATA

Table D.1: Transition rates (occ/hr) of the rapid start unit.

λ_{11}=0.0	λ_{12}=0.005	λ_{13}=0 0	λ_{14}=0.03
λ_{21}=0.0033	λ_{22}=0.0	λ_{23}=0.0008	λ_{24}=0 0
λ_{31}=0.0	λ_{32}=0 0	λ_{33}=0 0	λ_{34}=0.025
λ_{41}=0.015	λ_{42}=0.025	λ_{43}=0 0	λ_{44}=0 0

Table D.2: Transition rates (occ/hr) of the hot reserve unit.

λ_{11}=0.0	λ_{12}=0.024	λ_{13}=0.0	λ_{14}=0.0008	λ_{15}=0.0
λ_{21}=0.02	λ_{22}=0.0	λ_{23}=0.00002	λ_{24}=0.0	λ_{25}=0.0
λ_{31}=0.0	λ_{32}=0.0	λ_{33}=0.0	λ_{34}=0.03	λ_{35} =0.0
λ_{41}=0.035	λ_{42}=0.0	λ_{43}=0.0	λ_{44}=0.0	λ_{45}=0.025
λ_{51} =0.003	λ_{52} =0.0025	λ_{53}=0.0	λ_{54}=0.0	λ_{55}=0.0

IMAGE EVALUATION TEST TARGET (QA-3)

150mm

6"

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